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A DIVISION OF PACIFICORP

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July 26, 2024

***VIA ELECTRONIC FILING***
***AND OVERNIGHT DELIVERY***

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

**Re: UE 433—PacifiCorp's Reply Testimony and Exhibits**

PacifiCorp d/b/a Pacific Power hereby submits for filing the Reply Testimony and Exhibits of Matthew D. McVee, Nikki L. Kobliha, Ann E. Bulkley, Joelle R. Steward, Maryia V. Coleman, Rick T. Link, Richard A. Vail, Timothy J. Hemstreet, Brad D. Richards, Allen Berreth, James Owen, Ramon J. Mitchell, Kenneth L. Elder, Jr., Sherona L. Cheung, Anna DeMers, and Robert M. Meredith.

Included with this filing are the confidential and non-confidential electronic workpapers. Confidential material in support of the filing has been provided to parties electronically under Order No. 23-132.

Please direct any informal correspondence and questions regarding this filing to Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

Enclosures

Cc: UE 433 Service List

## CERTIFICATE OF SERVICE

I certify that a true and correct copy of **PacifiCorp's Reply Testimony & Exhibits** was served on the parties listed below via electronic delivery in compliance with OAR 860-001-0180.

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Dated this 26th day of July, 2024.

Carrie Meyer
Adviser, Regulatory Operations

Docket No. UE 433
Exhibit PAC/2000
Witness: Matthew D. McVee

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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# Reply Testimony of Matthew D. McVee

**July 2024**

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## ATTACHED EXHIBIT

Confidential Exhibit PAC/2001—Moody's Downgrade of Sierra Pacific Power

**Q. Are you the same Matthew D. McVee who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?**

A. Yes.

## I. PURPOSE AND SUMMARY OF TESTIMONY

**Q. What is the purpose of your reply testimony in this proceeding?**

A. I respond to the opening testimony of Public Utility Commission of Oregon (Commission) Staff witnesses Matt Muldoon, Michele Scala, Laurel Anderson, Curtis Dlouhy, Julie Dyck, Melissa Nottingham, and Nicola Peterson, Oregon Citizens' Utility Board (CUB) witnesses Bob Jenks and Sarah Wochelle, Alliance of Western Energy Consumers (AWEC) witness Lance D. Kaufman, and joint testimony filed by Community Energy Project witness Charity Fain, Verde witness Anahi Segovia Rodriguez, and Coalition of Communities of Color witness Nikita Daryanani (jointly, the Coalition).

**Q. Please summarize your testimony.**

A. First, I provide an overview of the Company's reply testimony, which reduces its overall rate increase request from $322.3 million to $214.5 million, or 11.9 percent. This proposed change in rates is comprised of (1) a base rate increase of $127.6 million, (2) the recovery of forecasted and deferred insurance premiums through the Insurance Cost Adjustment (ICA) of $66.0 million, (3) the estimated true-up of $21.2 million for the Wildfire Mitigation Plan automatic adjustment clause; and (4) the rebalancing of the Rate Mitigation Adjustment for a reduction of $0.4 million. The Company's reply testimony reduces the Company's base rate increase to

$127.6 million, approximately $30 million less than the Company's initial filing. The main driver is a reduction of the Company's requested return on equity (ROE) from 10.3 percent to 9.65 percent to mitigate the rate increase in this case and address parties' concerns about affordability. The Company has also removed $77.7 million for proposed funding of the Catastrophic Fire Fund (CFF) from this case to allow time for additional development of this proposal.

Second, I respond to several policy issues parties raised in opening testimony, specifically: (1) concerns regarding rate shock; (2) proposals to reduce wildfire restoration and excess liability insurance costs in this case; (3) issues and concerns regarding the low-income discount, service disconnections, and stakeholder input on environmental justice; (4) CUB's prudence disallowance for the Jim Bridger gas conversion; (5) Staff's opposition to the amortization of the Company's Distribution System Plan (DSP) deferral; (6) AWEC's proposals around Exit Orders, depreciation, and decommissioning costs; and (7) "placeholders" suggesting an intention to inappropriately raise new issues in rebuttal testimony.

Finally, I introduce the Company witnesses that provide reply testimony in support of the Company's requested overall rate increase.

## II. OVERVIEW OF REPLY FILING

**Q. Please provide an overview of PacifiCorp's reply filing.**

A. The Company has reduced its overall proposed rate increase to $214.5 million. This reflects a reduction to the requested base rate increase and the withdrawal of the CFF from the case. As detailed in the reply testimony of Company witness Sherona L. Cheung, the Company's reply filing seeks an overall base rate increase of

$127.6 million. The major drivers of the $30 million decrease from the initial filing are the ROE update, a $23.5 million reduction, and removal of the customer service system upgrade project (CSP) because of a delayed in-service date, a $6.3 million reduction. The reply testimony of Company witness Joelle R. Steward discusses the Company's withdrawal of the CFF from this proceeding.

**Q. Please explain the changes in the Company's proposed cost of capital in its reply filing.**

A. The Company reduced its requested ROE from 10.3 percent to 9.65 percent to mitigate the impact of this rate change on its customers. Even though Company witness Ann E. Bulkley's analysis continues to support an ROE range of 10.25 percent to 11.25 percent and PacifiCorp faces multiple challenges that affect its ability to attract capital, such as wildfire risk, the risk of under-recovery of substantial capital expenditures, and regulatory risks relating to fuel costs and lack of revenue stabilization,[1] PacifiCorp reduced its requested ROE to address customer concerns about rate affordability. PacifiCorp made this proposal even though its capital costs continue to increase, as reflected in the Company's updated cost of debt, now at 5.28 percent, an increase of $2.7 million. These changes in ROE and cost of debt combine to reduce the Company's proposed overall cost of capital from 7.74 percent to 7.47 percent. Company witnesses Bulkley and Nikki L. Kobliha address ROE and cost of debt, respectively, in their reply testimony.

**Q. Is 9.65 percent a conservative ROE for PacifiCorp?**

A. Yes. As discussed in greater detail in the testimony of Company witness Bulkley, the

[1] These risks are discussed in greater detail in the testimony of Company Witness Bulkley. PAC/400, Bulkley/50-71.

Company's cost of capital has increased significantly since the Commission approved a stipulation with a 9.5 percent ROE in the Company's last rate case, docket UE 399, in 2022.[2] This increase is reflected in various data points, including the federal funds rate, Treasury bond rates, and average ROEs. As reported in the opening testimony of Walmart, the average ROE for vertically integrated utilities in 2022 was 9.6 percent; thus far in 2024, it is 9.72 percent.[3] Especially given the profound risks PacifiCorp now faces, an ROE of 9.65 percent is conservative and reflects the Company's commitment to rate affordability.

**Q. Do you have other concerns relating to parties' recommendations regarding regulatory risk?**

A. Yes. Parties, including Staff, introduce arguments that are contrary to prior Commission policy, making it more difficult for the utility to anticipate its risk. For example, Staff recommends the implementation of a new rate base methodology that Staff describes as a "13-month average-of-monthly averages" for electric plant in-service (EPIS) rate base, and Staff now opposes the Company's long-standing use of a 2024 end-of-period EPIS rate base methodology. As explained in greater detail in the reply testimony of Company witness Cheung, Staff's recommendation is contrary to the matching principle, is based on an incomplete understanding of the Company's approach to calculating EPIS rate base, and results in an incorrectly calculated adjustment. Moreover, objections like Staff's new opposition to the methodology that the Company has used for the past five rate cases without any previous objection

[2] *In the Matters of PacifiCorp, dba Pacific Power, Request for a General Rate Revision,* Docket Nos. UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, and UM 2201 (cons.), Order No. 22-491 (Dec. 16, 2022).
[3] Walmart/100, Austin/9.

from Staff increase PacifiCorp's regulatory risk because the Company cannot anticipate what challenges will arise when it seeks rate support.

**Q. What other modifications to PacifiCorp's requested overall rate increase does the Company propose in this case?**

A. One of the drivers of PacifiCorp's requested overall rate increase was the initial contribution to a multi-state insurance fund for catastrophic fire losses, the CFF. Various parties responded to this proposal by suggesting that the Company remove the CFF from this case to allow more time for resolution of critical design issues, including cost allocation, and exploration of potential legislative solutions, all of which the Company could present to the Commission in a later filing. As set forth in the reply testimony of Company witness Steward, the Company has agreed to this approach, removing the CFF from this case with the understanding that the Company will re-file a refined CFF proposal in 2025. As part of this proposal, the Company is withdrawing its request for $77.7 million to begin funding Oregon's share of the CFF starting January 1, 2025. This results in a 4.3 percent reduction from the Company's initial filing.

**Q. In addition to the CFF, PacifiCorp also proposed the ICA. Does PacifiCorp's removal of the CFF from its reply filing case affect the Company's ICA request?**

A. No. The Company still proposes to recover third-party liability insurance costs (both deferred and on-going) through a separate tariff rider, the ICA. Company witness Steward discusses the ICA in greater detail in her reply testimony. The Company is not proposing to implement a new insurance mechanism for self-insurance in this

case. Instead, the Company will continue to develop that proposal with stakeholders, with a target filing date in 2025.

**Q. PacifiCorp's initial filing included several major capital investments, including the Gateway South and Gateway West Segment D.1 transmission lines (collectively, Gateway South segments), the Rock Creek I wind project, the Rock River I wind project, and the Company's customer service system upgrade, the CSP.[4] Is there any update on the status of these major capital additions?**

A. Yes. PacifiCorp's CSP has been delayed and will not be in service until after the January 1, 2025 rate effective date. Accordingly, PacifiCorp is removing the CSP from the Company's revenue requirement for this case. All other major capital additions remain on schedule and on budget.

**Q. Is timely recovery of these capital projects critical to PacifiCorp's financial health?**

A. Yes. These projects are large-scale construction that require long lead times to plan and complete. By the time the Company seeks to include these projects in its rate base, PacifiCorp has already incurred substantial costs. Delaying or discounting recovery of these costs would limit PacifiCorp's ability to invest in and develop subsequent projects that will improve service to customers and enable the Company to comply with state policies, including the clean energy goals adopted in House Bill (HB) 2021.[5]

[4] PAC/200, McVee/6.
[5] *See* Confidential Exhibit PAC/2001 (Moody's Downgrade of Sierra Pacific Power Company).

**Q. Staff witness Sudeshna Pal testifies that while Staff has not yet reached a definitive conclusion, it cannot find the Gateway South segments prudent.[6] However if the Commission finds the projects prudent, Staff recommends that PacifiCorp's rate of return for Gateway South segments should be reduced to the modified blended treasury rate of 5.4 percent with a "management disallowance" of 10 percent of the Oregon-allocated share of the Gateway South investment.[7] Is Staff's recommended disallowance appropriate?**

A. No, the Company disagrees strongly with the assertion that the Gateway South segments were not prudent and the proposed adjustment is warranted, as explained in detail in the reply testimony of Company witnesses Rick T. Link and Richard A. Vail. Successful construction of a 300-mile plus interstate transmission line is a major undertaking, one that takes years of planning, permitting and regulatory approvals. PacifiCorp remains on track to complete the Gateway South segments on time and on budget, despite the headwinds caused by COVID-19 and post-COVID-19 supply chain issues. This is a major accomplishment, one critical to meeting PacifiCorp's resource needs, regional resource adequacy, federal transmission obligations, and PacifiCorp's compliance with HB 2021.

Staff's adjustment fails to recognize any of this, instead arbitrarily concluding that 5.4 percent is a reasonable return on the Gateway South segments, regardless of what the Commission determines to be a reasonable return on the Company's overall rate base and proposing a 10 percent "management disallowance" of the Oregon-allocated project costs. However, Staff has not provided any calculations or detailed

[6] Staff/1400, Pal/22.
[7] Staff/1400, Pal/23, 26.

rationale to justify either disallowance. Instead, Staff explained in response to a data request (DR) that "it is not possible to precisely quantify the risk PacifiCorp's actions imposed on customers or to quantify the harm to customers from PacifiCorp's planning and management deficiencies,"[8] and instead bases its recommendation on only a generalized (and incorrect) conclusion that the transmission line will be under-utilized. The testimony of Company witnesses Link and Vail make clear that, given existing transmission constraints in the region, the line will be fully utilized under any future scenario and the Company expertly planned and constructed the line.

Staff's recommendation is inconsistent with the matching principle because Staff seeks to reduce the costs included in rates for the Gateway South segments but makes no adjustment to the benefits Oregon customers will receive. The Gateway South segments enable substantial benefits, including interconnection of over 1,600 megawatts (MW) of emission-free, Production Tax Credit-eligible wind resources selected through the 2020 All-Source Request for Proposals. These Gateway South segments are also lynchpins in PacifiCorp's ability to meet its obligation to provide generator interconnection service and transmission service. Staff does not indicate in its testimony that any of these benefits will be removed from rates, and instead suggests disallowing a portion of only the costs.

The Gateway South segments represent a substantial investment in resources to provide safe, reliable generation for Oregon customers and to interconnect resources that will help PacifiCorp comply with Oregon clean energy goals. Staff's adjustments discourage future capital investments by putting utilities on notice that

[8] Staff Response to PacifiCorp DR 14.

cost recovery for critical, prudent infrastructure projects is at risk, despite delivery of significant benefits to Oregon customers. This undermines utility compliance with HB 2021's emissions mandates. Company witnesses Link and Vail further address Staff's testimony regarding the prudence of the Gateway South segments and their reasonable management.

**Q. Staff witness Julie Dyck raises concerns about PacifiCorp's investments in the Juniper Ridge Bend Service Center and testifies that Staff believes "it is unreasonable to expect that 35 percent of the Project costs would occur in the 10 months prior to project being placed in service, given that it was started in 2019."[9] How do you respond?**

A. Staff witness Dyck's concerns regarding the Juniper Ridge Bend Service Center are addressed in the reply testimony of Company witness Allen Berreth, who explains that the remaining cost to be spent on the project is $7.7 million, not $14.2 million as Staff has indicated. The remaining construction activities are almost entirely committed and scheduled and validate the forecasted project costs. Additionally, as Staff witness Luz Mondragon discusses in her testimony, PacifiCorp's historical estimates of costs for capital additions have been very accurate, "which increases Staff's confidence in the quality of the Company's projections."[10] Specific to the concern regarding whether the Company will actually incur the estimated costs, the Commission has previously resolved similar concerns with post-construction

[9] Staff/800, Dyck/21.
[10] Staff/1100, Mondragon/12 (explaining that the 2022 additions PacifiCorp projected in Docket No. UE 399 were within two percent of the actual additions reported in the Company's 2022 Results of Operations report).

attestations from the Company.[11] PacifiCorp agrees to submit such an attestation verifying that the Juniper Ridge Bend Service Center is placed in service by the rate effective date.

## III. RATE SHOCK

**Q. Staff and CUB both raised concerns regarding rate shock. Does PacifiCorp consider rate shock when determining whether to prepare a general rate case (GRC)?**

A. Yes. The Company understands Staff's and CUB's concern and takes seriously the impact on customers associated with rate increases of any magnitude. However, recent rate increases have largely been the product of forces that are outside the Company's control, like market conditions and inflation, and are reflective of the costs to serve customers and advance Oregon state energy policies that Staff and CUB expressly support.

**Q. CUB testifies that PacifiCorp's residential rates have increased 35.2 percent since 2021 and if the Commission approves the rate increase requested in this GRC residential customers' rates will have increased by 64.4 percent between 2021 and 2025.[12] How do you respond?**

A. First, as noted above, PacifiCorp has decreased its overall proposed rate increase by 6.0 percent in its reply filing and decreased the proposed residential rate increase by 6.7 percent. Second, until the last few years, PacifiCorp customers enjoyed a long

[11] *In the Matter of PacifiCorp, dba Pac. Power Request for a Gen. Rate Revision*, Docket No. UE 374, Order No. 20-473 at 32 (Dec. 18, 2020).
[12] CUB/200, Wochele-Jenks/36.

period of flat or decreasing rates,[13] so the percentage increases CUB cites are from a low base level. Third, PacifiCorp is dedicated to keeping its rates as low as possible for customers, while still making the investments necessary to provide safe and reliable service in compliance with Oregon's comprehensive environmental and wildfire mitigation mandates. The drivers of the rate changes in the last few years are much higher net power costs (NPC), critical infrastructure investments, and wildfire mitigation. Controllable costs such as normal operations, maintenance, administrative and general costs have not contributed materially to PacifiCorp's recent rate changes.

**Q. How much of the recent rate changes were related to the TAM and the Power Cost Adjustment Mechanism (PCAM)?**

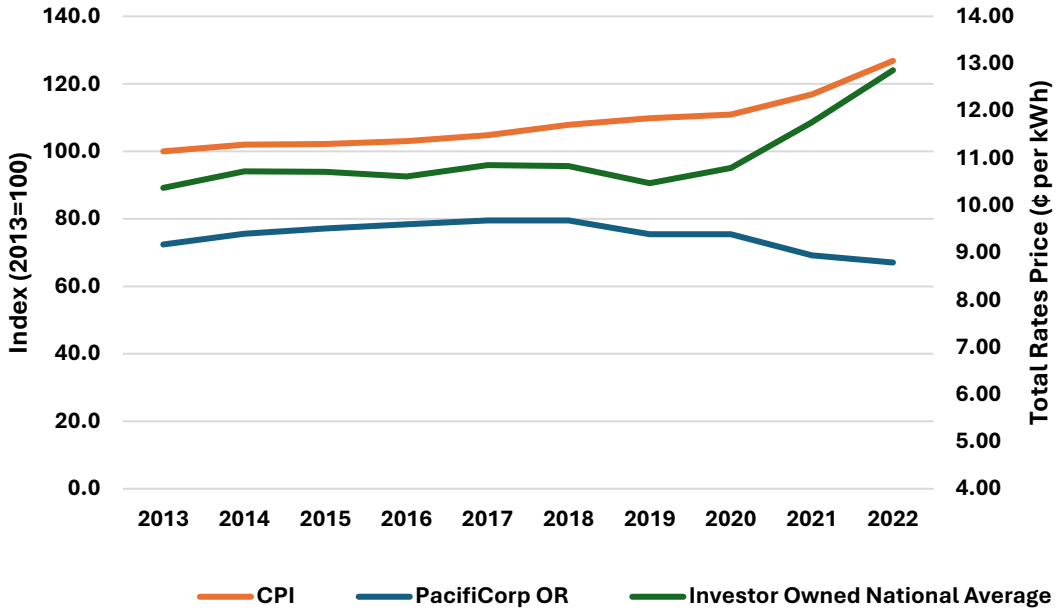
A. PacifiCorp's TAM is an annual filing in which PacifiCorp projects the amount of NPC to be reflected in customer rates for the following year, as well as to set transition charges for customers electing to move to direct access. The final TAM rate change for January 1, 2023, was an increase of 11.1 percent and the final TAM rate change for January 1, 2024, was an increase of 8.7 percent. This means that 19.8 percent of rate changes in the last two years were related to increasing forecast NPC. The PCAM is a partial true-up of forecast and actual NPC. The PCAM rate changes during 2023 and 2024 were five percent. Combined, NPC-related increases constitute a total of 24.8 percent to customers.

[13] *See, e.g.*, *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 1 (Dec. 18, 2020) (approving a decrease to PacifiCorp's revenue requirement of $20.9 million or 1.6 percent). Additionally, the transition adjustment mechanism (TAM) filing that year further reduced customers' rates by $49.8 million or 3.8 percent. *In the Matter of PacifiCorp, dba Pac. Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392 at 1 (Oct. 30, 2020).

**Q. Have PacifiCorp's rates remained below both the Consumer Price Index (CPI) and national averages for many years?**

A. Yes, as demonstrated by Figure 1 below, PacifiCorp's Oregon customers have benefitted from below-average rates and rate changes for the last decade.[14]

**Figure 1: PacifiCorp's Rates Compared to CPI and National Averages**



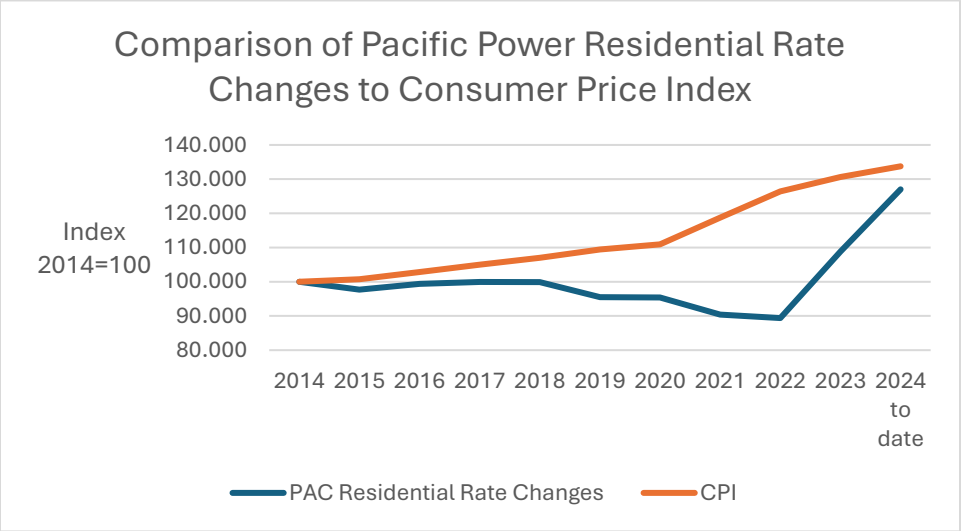

Source: EEI Typical Bills and Avg

**Q. Looking specifically at PacifiCorp's residential rates, have these rates either decreased or increased at levels below the CPI for the last decade?**

A. Yes. Figure 2 below provides a comparison of PacifiCorp's all-in residential rates since 2014 and the CPI. As shown in Figure 2, the Company's residential rates decreased prior to 2022 and, even with the recent increases, the cumulative increase in PacifiCorp's rates since 2014 is less than the cumulative increase in CPI.

[14] Figure 1 uses the most recent data from Edison Energy Institute (EEI), through 2022, for national average electric rates.

**Figure 2: PacifiCorp's Rates Compared to Consumer Price Index[15]**




**Q. Has PacifiCorp matched its rate changes over the past two years with increased customer benefits?**

A. Yes. While PacifiCorp's rates have increased in the past two years, these increased rates have provided commensurate benefits to customers. These benefits include investments in improving safety and reliability on the system, mitigating wildfire risk, and reducing emissions in accordance with Oregon's clean energy goals. As noted above, the majority of PacifiCorp's recent rate increases are due to higher NPC caused by market forces, outside the Company's control. And customer rates do not reflect the full impact of these NPC increases—as Company witness Kobliha explains in her reply testimony, from 2021 through 2023, PacifiCorp absorbed approximately $121 million of the increased NPC.[16]

[15] Consumer Price Index for All Urban Consumers, December. Source: Bureau of Labor Statistics, https://data.bls.gov.
[16] Kobliha Reply Testimony, Exhibit PAC/2100 at 7.

**Q. Staff and CUB raise concerns about the combined impact of the general rate increase and the TAM. Do you have any update regarding potential rate impacts of the 2025 TAM?**

A. Yes. PacifiCorp's initial filing in the 2025 TAM projected a rate *decrease* of approximately $18 million, or one percent.[17] The parties in PacifiCorp's 2025 TAM recently filed a stipulation that will limit any potential rate increase in the 2025 TAM by providing a $13 million reduction.[18] The TAM reply update, net of this settlement benefit, reflects a rate decrease of $23.1 million, or 1.3 percent. Additionally, PacifiCorp agreed that if the rate increase to residential customers from the final 2025 TAM update exceeds 10 percent, PacifiCorp will defer, at the modified blended Treasury rate, collection of the costs above 10 percent for residential customers. In summary, the 2025 TAM appears likely to mitigate the impact of rate changes in this case, not add to them.

**Q. Staff witness Matt Muldoon and CUB witness Bob Jenks both raise concerns regarding aggregate rate impacts to customers from rate changes in this rate case and other dockets such as PacifiCorp's TAM.[19] How do you respond?**

A. It is my understanding that the Commission has historically reviewed rate shock issues—and potential rate design solutions—in a particular rate case without considering the impact of a utility's other pending or future filings in that review.[20]

[17] *PacifiCorp 2025 Transition Adjustment Mechanism*, Docket No. UE 434, PAC/100, Mitchell/6 (Feb. 14, 2024).
[18] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2025 Transition Adjustment Mechanism*, Docket No. UE 434, PacifiCorp's Motion to Modify Procedural Schedule (June 28, 2024).
[19] Staff/100, Muldoon/11; CUB/100, Jenks/5-7.
[20] *See, e.g., In the Matter of the Application of Portland General Electric Company for an Investigation into Least Cost Plan Plant Retirement*, Docket Nos. DR 10, UE 88, UM 989, Order No. 08-487, at 76 (Sept. 30, 2008) (rejecting the proposal of CUB and Staff to adjust the amount of recovery in other dockets to balance rate shock in the current docket).

**Q. Staff witness Melissa Nottingham provides a summary of public comments received in this docket and testifies that "[a]ffordability is the predominate issue raised in opposition" and that comments were concerned with the broader economic hardships consumers face.[21] How do you respond?**

A. PacifiCorp takes seriously its efforts to address affordability concerns, as demonstrated in the adjustments PacifiCorp made to its reply filing. In addition, to mitigate customers' energy burden, PacifiCorp has implemented several programs to assist customers, which are discussed in greater detail below in Section IV of my testimony and in the reply testimony of Company witness Robert M. Meredith. PacifiCorp continues to collaborate with stakeholders to improve its programs to address customers' potential energy burden.

**Q. Staff witness Nottingham also states that comments have indicated that rates are increasing at a pace that exceeds income growth. How do you respond?**

A. As discussed above, while PacifiCorp's rates have increased in the past two years largely as a result of increased NPC, PacifiCorp's rates had remained flat or declined until these recent increases. PacifiCorp's rates over the past decade have increased at a rate slower than that of the CPI.

[21] Staff/1300, Nottingham/2-3.

**Q. Staff testifies that it believes "the Company's proposed revenue requirement and rate spread overburdens residential customers on a practical level and should be revised to more thoughtfully consider affordability and weigh how the spread will impact energy security across different customer groups" and recommends that "final determination of rate spread in conjunction with revenue requirement ensure that the residential class sees an increase of no more than 8 percent of revenue requirement[.]"[22] How do you respond?**

A. To the extent that Staff is proposing that the Commission cap the revenue requirement the Company may recover based on rate shock, this is contrary to Commission precedent. I understand that the Commission considers rate shock in developing rate spread and rate design, not in determining revenue requirement.[23] Based on that precedent, the Commission should not limit the Company's revenue requirement based on Staff's rate shock concerns.

To the extent Staff is proposing to change rate spread to limit the rate impact on residential customers, Staff's recommendation would shift costs onto other customer classes. As detailed in the testimony of Company witness Meredith, the Company has allocated the revenue requirement to each rate schedule based on the results of the functionalized class cost of service study.

[22] Staff/300, Scala/30-31.

[23] *In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 115, Order No. 01-842, at 4 (rejecting the argument that "regardless of the prudency of the utility's expenditures, rate increases that cause rate shock are not just and reasonable"); *see also* Order No. 01-988 (discussing rate shock generally); *In the Matter of Pacific Power & Light (dba PacifiCorp), Request for a General Rate Increase*, Docket No. UE 170, Order No. 06-172, at 18 (Apr. 12, 2006) (noting that the Commission "may *mitigate* the impact of rate changes to help avoid rate shock," but applying that authority only to the principle of gradualism in allocating rates among different customer classes) (emphasis added).

In either case, Staff has not provided any calculation or justification explaining how it selected 8 percent for its proposed cap or how prudent costs over the cap amount would be recovered. For example, it is not clear whether Staff is proposing to limit the rate increase by assigning a greater proportion to non-residential customers or if Staff means to defer some portion of the increase and incrementally increase residential rates by 8 percent at set intervals. Either way, Staff has not provided any support for the specific limit selected.

**Q. Staff testifies that it is "concerned with shifting risk from utilities onto customers on the grounds of which entity is best poised to absorb any given risk with the least amount of harm."[24] How do you respond?**

A. The Commission does not set rates based on an assessment of whether a utility or customers are better positioned to absorb the prudent costs of electric service. As Staff notes, PacifiCorp is obligated to provide service to all customers within the Company's service territory.[25] In return, the Company is entitled to recover its prudent costs of service, irrespective of its ability to absorb risk relative to customers, through fair and reasonable rates.[26] Moreover, if Staff proposes to shift risk to PacifiCorp, the Company should receive a commensurate increase in its ROE to address the increased risk. Company witness Bulkley discusses the ROEs that comparable utilities have received in the current risk environment. Company witness Bulkley also discusses specific factors that have increased the risks for utilities

[24] Staff/300, Scala/20.
[25] Staff opposes provisions that would allow PacifiCorp to deny a load request if capacity is not available Staff/700, Dlouhy/11. *See* ORS 757.020 (public utility has a statutory obligation to furnish adequate and safe service); ORS 757.603 (public utility must provide all retail electricity consumers connected to its distribution system with a regulated, cost-of-service rate option for service).
[26] ORS 756.040.

operating in Oregon, and those difficulties will be exacerbated if Staff's proposal to shift additional risk to the Company is adopted.

Finally, while Staff asserts that PacifiCorp is better poised to absorb risk, Staff fails to consider how PacifiCorp has been impacted by the increasingly risky environment for utilities operating in Oregon, which is discussed in greater detail in Company witness Bulkley's testimony. Contrary to Staff's suggestion, PacifiCorp cannot absorb escalating risks without strong regulatory support.

**Q. Does CUB make any recommendations regarding rate shock?**

A. Yes. CUB recommends that the Commission design a "policy around rate shock that can be implemented even in cases where the rate shock is not evident early in the year."[27]

**Q. How has the Commission previously considered rate shock?**

A. The Commission has historically considered rate shock on a case-specific basis using rate spread and rate design tools. As CUB acknowledges in its testimony, these issues are often resolved through stipulations which provide additional flexibility to fashion solutions. While CUB testifies that it does not believe stipulations are the best way to resolve rate shock concerns, CUB has supported these stipulations in other cases.[28]

**Q. In your opinion, is it appropriate to incorporate a broad policy like CUB proposes in a GRC?**

A. No. It is my understanding that CUB has proposed this same rate shock policy in other GRCs this year filed by Idaho Power Company and NW Natural. CUB witness Jenks's testimony acknowledges that the Commission has never done what

[27] CUB/100, Jenks/13.
[28] *See, e.g.*, Docket No. UE 374, Order No. 20-473 at 2 (Dec. 18, 2020).

CUB is suggesting here—adopt a one-size-fits-all approach that would apply to all energy utilities.[29] A one-size-fits-all policy for multiple utilities in Oregon should be considered and adopted in a broad policy docket, where stakeholders from all utilities, industries, and customer groups may participate.

**Q. Does CUB identify any standard to guide this rate shock policy?**

A. Yes. CUB recommends that the Commission adopt a policy similar to recently adopted legislation limiting residential rent increases.[30] That standard limits annual rent increases to the lower of either 10.0 percent or 7.0 percent plus the increase in the CPI. CUB asserts that this is a relevant consideration because utilities are a part of the cost of housing.[31] CUB proposes that any residential rate increase that exceeds that annual limit should trigger a rate shock finding and require application of tools to mitigate that shock.

**Q. Do you agree that the legislative cap on rental increase is a proper analogue to increases in utility rates?**

A. No, I do not. CUB's proposal ignores substantial differences in how utilities are regulated compared to the rental housing market. Unlike rental housing, utilities are subject to cost-of-service regulation, which limits utilities' cost recovery to their prudently incurred costs approved by the Commission. The same is not true of the rental housing market where rents are set based on supply-and-demand. In situations where the demand for rental housing exceeds supply, landlords may increase their rent, even if there is no commensurate increase in the costs they incur to make such

[29] CUB/100, Jenks/12.
[30] CUB/100, Jenks/13.
[31] ORS 90.324(1)(a)-(b).

rental housing available to the market. Regulated utilities cannot take similar actions. Instead, their rates reflect the cost to serve customers, and are closely regulated by the Commission.

**Q. What other components does CUB propose for its rate shock policy?**

A. CUB recommends that the rate shock policy include: (1) deferring or phasing in the rate increase—with or without carrying charges; (2) setting the ROE at a level that is not lower than the lowest reasonable rate; and (3) requiring the utility to propose and implement other rate mitigation measures.[32]

**Q. Is delaying recovery of approved rate changes appropriate?**

A. No. Deferring or delaying rate changes prevents utilities from timely recovering prudently incurred costs that are necessary to provide essential services. It is also contrary to the regulatory compact where utilities are subject to economic regulation by the Commission in exchange for the opportunity to timely recover prudently incurred costs.

Additionally, delaying recovery of prudently incurred costs fails to adequately consider the significant costs the Company has invested in providing service in Oregon. As discussed in the testimony of Company witness Bulkley, a utility's risk profile may be adversely affected when a heightened level of capital investment increases the risk of under recovery or delayed recovery of invested capital. PacifiCorp has and continues to make substantial investments to serve customers reliably and safely, and to comply with Oregon's environmental obligations, such as the clean energy policies included in HB 2021. Capping or delaying PacifiCorp's

[32] CUB/100, Jenks/11-12.

recovery of prudent costs would make it more difficult for the Company to access capital at reasonable costs in order to make continued investments that serve Oregon customers.

**Q. Has PacifiCorp proposed phasing in rate changes in other states?**

A. Yes, in the Company's pending general rate cases in Idaho and Utah, it has proposed phasing in recovery of NPC, but not other cost items.[33] Importantly, while PacifiCorp proposed phasing in the increase to base NPC, the Company would recover the entirety of these costs over that time.

**Q. As a matter of policy, do you agree that the Commission should limit approved ROEs to the lowest reasonable return?**

A. No, I do not. CUB's proposal to limit the ROE to the lowest reasonable return, which CUB has recommended for multiple utilities, ignores the utility-specific circumstances the Commission must consider when setting ROE. Moreover, as discussed above, PacifiCorp has reduced its requested ROE in this case.

**Q. Staff similarly testifies that the "Commission could consider using ROE as a throttle to control the frequency of general rate cases."[34] How do you respond?**

A. Unfortunately, Staff omits important context in its discussion of the timing of PacifiCorp's recent rate cases. Staff testifies that the Commission could consider this

[33] *Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Utah Pub. Serv. Comm'n Docket No. 24-035-04, Direct Testimony of Joelle R. Steward at 15 (June 28, 2024) (available at https://pscdocs.utah.gov/electric/24docs/2403504/334481DirTstmnyJoelleRStewardRMP6-28-2024.pdf) (last visited July 18, 2024); *In the Matter of 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*, Idaho Pub. Util. Comm'n Case No. PAC-E-24-04, Direct Testimony of Joelle R. Steward (May 31, 2024) (available at https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/PAC/PACE2404/Company/20240531Direct%20J.%20Steward.pdf) (last visited July 18, 2024).

[34] Staff/100, Muldoon/15.

approach because this docket is the Company's third GRC to take effect since 2021. Staff suggests that "the Commission might determine that frequent rate case filing would merit a ten percent lower ROE within a range of reasonable ROEs."[35] However, Staff's discussion of timing without context obscures the underlying facts to support its argument. First, while Staff is correct that this is the third change PacifiCorp has proposed to its base rates in the last five years, in 2020, docket UE 374 resulted in a rate *decrease* of approximately $20.9 million, as ordered, which grew to a $66.8 million decrease following the identification of projects that did not reach completion through the attestation process.[36] Second, it is important to contextualize the underlying cause of the recent rate changes. As explained above, rising NPC has caused the majority of recent rate increases. Reducing PacifiCorp's ROE will not mitigate the rate increases that result from NPC, nor change the annual TAM filings required by the Commission's rules. Nor will reducing ROE support investments to meet state energy policy under HB 2021.

**Q. What additional rate shock mitigation actions does CUB recommend when a rate increase exceeds the proposed threshold?**

A. CUB recommends that the Commission require a utility to take the following actions:

1. The rate effective date associated with costs that do not need to be recovered during the winter months should be delayed and not placed on winter bills.
2. The utility should be required to submit a plan to the Commission outlining what it is doing to mitigate the rate shock. This plan should

[35] Staff/100, Muldoon/16.
[36] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 1 (Dec. 18, 2020); *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, PacifiCorp Advice No. 20-017 (Dec. 28, 2020).

include increasing efforts to educate customers about programs that might help the customer deal with the impact.

3. A shut-off moratorium should be implemented for a six-month period.
4. For 12 months after the increase, the utility should be required to report to the Commission the number of customers, by zip code, who have 30-day arrearages, the number that have 60-day arrearages, the number that have received shut off notices, the number that have been shut off and any other information the Commission believes will be helpful in understanding the impact of the increase.[37]

**Q. Does CUB propose applying its rate shock policy in this case?**

A. Yes. The Company's initial filing proposed an increase of 17.9 percent, which would exceed CUB's proposed threshold.

**Q. CUB's first recommended rate shock mitigation tool is to delay the rate effective date until after the winter months. How do you respond to this recommendation?**

A. While PacifiCorp understands CUB's concern about increased rates during winter months, the Company is concerned that shifting even more costs into the summer season may provide temporary winter relief but will create its own issues when customers are faced with higher-than-expected summer bills. To the extent that CUB's proposal seeks to smooth out bills over the course of the year, customers can already take advantage of equal payment plans to achieve the same basic outcome.

[37] CUB/100, Jenks/17.

The Company also has a low-income bill assistance program to help alleviate the pressure on low-income customers caused by increasing rates.

**Q. CUB's second recommended rate shock mitigation is to require a utility to submit a plan detailing its efforts to mitigate rate shock, including outreach programs. How do you respond?**

A. PacifiCorp has reached out to customers with past-due balances to educate them about available options. PacifiCorp targeted outreach in areas where the average arrears or per customer arrears were higher and where the median income is below the State Median Income (SMI). PacifiCorp identified customers using census tract and county data and overlayed that geographic data with arrears data. In November 2023, PacifiCorp deployed postcards and email outreach targeting all customers with arrears. PacifiCorp sent postcards to approximately 61,000 customers and emails to approximately 234,000 customers (those who have email addresses on file with the Company). This outreach program effectively contacted all customers with arrears to highlight the Company's bill assistance programs.[38] The Company also includes bill inserts informing eligible customers of PacifiCorp's bill assistance programs.[39]

**Q. CUB next proposes a shutoff moratorium for six months. Does PacifiCorp support such a moratorium?**

A. No, PacifiCorp does not believe a broad moratorium such as the one CUB proposes would be appropriate. For one thing, the Commission's Division 21 rules already limit power shutoffs during cold weather, particularly with recent revisions in 2022

[38] Response to Coalition DR 3.
[39] For example, PacifiCorp informs customers of their automatic enrollment in the Company's Low Income Discount program. https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/Tier%201M_General_OR_LID_Bill_Onserts_PP.pdf

which expanded the cold weather moratorium parameters for all customers, limited reconnection fees, and prohibited late payment fees for low-income customers.[40]

Moreover, PacifiCorp already weighs potential moratoria beyond those required by Commission rules. In the case of an event such as a pandemic, natural disasters, and/or severe weather events not already addressed in the Commission's Division 21 rules, the Company will meet internally to discuss the appropriate course of action when determining if a disconnection moratorium should be implemented. That said, as explained in Company witness Meredith's testimony, the Company has seen a significant increase in arrearages following the COVID-19 disconnection moratorium and is hesitant to implement any further moratoriums that might further increase arrearages and customer energy burden.

**Q. Finally, CUB recommends that a utility be required to provide detailed reporting of customers with arrearages. How do you respond?**

A. PacifiCorp provided comparable information to parties in this case through discovery. In addition, stakeholders are actively reviewing this topic in conjunction with additional potential energy burden reduction options in docket UM 2211. PacifiCorp proposes exploring potential reporting requirements with stakeholders in that docket, not here.

[40] OAR 860-021-0407.

**Q. CUB also testifies that the Commission could order the utility to suspend or reduce the amortization of certain deferred accounts or other single issue ratemaking mechanisms, to reduce the impact of the rate increase.[41] Do you agree that suspending amortization of those mechanisms would be appropriate?**

A. No. CUB does not specify which accounts or mechanisms should be suspended, but generally the purpose of deferred accounts and recovery mechanisms is to recover costs the Company has already prudently incurred serving customers. For example, the purpose of the PCAM is to allow PacifiCorp to recover the difference between actual NPC incurred to serve customers and the base NPC established in PacifiCorp's TAM. The Commission should not suspend or reduce recovery of these prudent costs that the Company incurred serving its customers.

## IV. WILDFIRE AND INSURANCE COSTS

**Q. Which Company witnesses reply to parties' testimony on wildfire insurance and cost recovery?**

A. The Company's reply testimony on wildfire insurance and cost recovery responds to the opening testimony of Staff witnesses Luz Mondragon, Nicola Peterson, Rose Pileggi, Bret Stevens, and April Brewer; CUB witness Bob Jenks; and AWEC witness Chad D. Wilcox. The Company's testimony on these issues is organized as follows:

- My testimony addresses parties' positions on the amortization of wildfire restoration costs (deferral of these costs was authorized in docket UM 2116) and wildfire insurance costs (deferral of these costs was authorized in docket UM 2301).

- The reply testimony of Company witness Steward responds to testimony regarding the Company's ICA and CFF proposals.

[41] CUB/100, Jenks/17.

- The reply testimony of Company witness Mariya V. Coleman provides the latest information on forecast wildfire insurance costs for the 2024-2025 period and replies to issues regarding the Company's insurance portfolio, including the impact of ongoing litigation arising from the 2020 Labor Day Fires on excess liability insurance rates and availability, and the prudence of the insurance expenses approved for deferral in docket UM 2301.

- The reply testimony of Company witness Cheung addresses recommendations of AWEC witness Kaufman regarding cost of capital calculations related to amortization of the docket UM 2116 deferred amounts, and responds to specific adjustments proposed by Staff to the docket UM 2116 deferral amortization amounts.

**Q. Please summarize the Company's reply testimony on wildfire issues.**

A. The parties' testimony generally recognizes the risks that wildfire liability, and the extraordinary costs required to insure against it, pose to the Company's (and other Oregon utilities') financial health and stability. The Commission itself summarized these concerns in an order issued on May 30, 2024, in docket UE 428:

> Oregonians have an interest in the solvency of their electric utilities, and unbounded wildfire verdicts can threaten that interest. A utility that cannot effectively secure financing or capital may struggle to meet growing demand, implement legislative mandates, maintain reliable service, and even make good on compensation owed to wildfire victims. Public policy and regulatory solutions to the problem of unbounded wildfire liability are urgently needed.[42]

PacifiCorp has offered several proposed regulatory solutions, in this proceeding and in other dockets,[43] to ameliorate the risks posed by the growing threat of wildfires in all the states the Company serves. In addition, as discussed in Company witness Steward's direct and reply testimony, the Company continues to sponsor a multi-state

[42] *In the Matter of PacifiCorp, dba Pacific Power, Advice No. 23-018 (ADV 1545), Modifications to Rule 4, Application for Electrical* Service, Docket No. UE 428, Order No. 24-021, at 1 (May 30, 2024).
[43] These include PacifiCorp's request to amend its tariffed limitations of liability, which the Commission declined to adopt in docket UE 428.

stakeholder forum created to seek consensus on wildfire liability issues, which all participants acknowledge are only growing in their complexity and cost.

In its reply testimony, the Company revises parts of its proposals to meet concerns expressed in parties' opening testimony.[44] Certain recommendations by the parties, however, will only serve to make these difficult problems worse. As discussed below, the arbitrary expense disallowances labeled as "sharing" are counter-productive and contrary to recent Commission decisions. Moreover, the justifications for proposals that would inappropriately reduce the recovery of wildfire system restoration and excess liability insurance costs rely on flawed regulatory theories that are not supported by the facts before the Commission.

## A. Docket UM 2116: Wildfire Damage and Restoration Costs

**Q. Please describe the issues from docket UM 2116 that are being considered in this proceeding.**

A. In docket UM 2116, the Commission approved the deferral of costs associated with the 2020 Labor Day wildfires, including costs for restoration of system assets damaged by the wildfires, to be netted with deferred revenue requirement amounts associated with undepreciated investments no longer used and useful due to wildfire damage.[45] The amortization of the deferred amounts into rates was included as an issue here when the Commission approved consolidation of docket UM 2116 into this proceeding. PacifiCorp details the deferred costs for which it seeks amortization, and

[44] For example, Company witness Steward discusses the withdrawal of the proposed Catastrophic Fire Fund to facilitate further development of the proposal before filing in a separate future docket.
[45] *In the Matter of PacifiCorp dba Pacific Power Application Deferred Accounting Related to Wildfire Damage and Restoration Costs*, Docket No. UM 2116, Order No. 22-154 (May 9, 2022).

the prudence of these costs, in the direct testimony of Company witnesses Berreth[46] and Cheung.[47]

**Q. What responses did the Company's amortization proposal receive in parties' testimony?**

A. Staff witness Mondragon proposed specific adjustments to the Company's calculations of the wildfire restoration costs to be included in rates.[48] These adjustments are addressed in the reply testimony of Company witness Cheung. In addition, however, Staff proposed a "sharing mechanism of 30/70 for restoration costs. This would mean the Company can recover 30 percent of costs from customers and the other 70 percent should be shared between PacifiCorp and its parent companies."[49] Staff's proposals would reduce the amortization of restoration costs by $13.3 million.[50]

**Q. What analysis leads Staff to argue that 70 percent of the Company's cost of restoring its systems after the 2020 wildfires should be disallowed from recovery in rates?**

A. Staff witness Mondragon's testimony recounts that in September 2020, "a number of devastating wildfires spread across Oregon causing widespread and extensive damage to PacifiCorp's transmission and distribution facilities and resulting in loss of power to customers."[51] Staff witness Mondragon goes on to describe the "legal issues related to the 2020 Wildfires," including the 2023 jury verdict in the *James* litigation and

[46] *See* PAC/1400, Berreth/8-10.
[47] *See* PAC/1700, Cheung/36-38 and Exhibit PAC/1702 (Oregon Results of Operations Report).
[48] Staff/1100, Mondragon/51-52.
[49] *Id.,* at Mondragon/52.
[50] *Id.*
[51] *Id.,* at Mondragon/45.

PacifiCorp's notice of appeal of the verdict. Finally, Staff witness Mondragon notes other pending legal matters arising from the Labor Day fires and the settlements the Company has reached with claimants related to the wildfires.[52] After Staff's recitation of these facts, Staff witness Mondragon states that "[i]n light of court findings," Staff proposes the 70 percent disallowance of the Company's wildfire restoration costs. That is the extent of the analysis underlying the Staff proposal. The specific "court findings" are not identified, and neither is the basis for choosing a 70 percent disallowance in the "sharing mechanism."

**Q. Is Staff's proposal consistent with prior Commission decisions regarding amortization of wildfire restoration costs in rates?**

A. No. For any utility, recovery of repair and restoration costs—whether involving wildfire, ice storms, or other emergency conditions—is essential to maintaining service during an emergency and restoring service for customers suffering from outages resulting from the emergency conditions. The rapid and efficient return to service is an essential part of a utility meeting its obligation to serve customers.

When the Commission has considered amortization of deferrals related to restoration costs, it has adopted earnings reviews or tests to fulfill its obligation under ORS 757.259(5) to "review the utility's earnings at the time of the application to amortize the deferral." But the Commission has rejected sharing proposals like the one offered by Staff in this case. In docket UE 394, Portland General Electric Company (PGE) sought to amortize deferred restoration costs stemming from the 2020 wildfires and 2021 ice storm. The Commission "decline[d] to adopt Staff's

[52] *Id.,* at Mondragon/50-51.

proposal for PGE to absorb 10 percent of the prudently incurred costs in the wildfire and ice storm deferrals."[53] The Commission reasoned that:

> We have designed the earnings test to achieve our intended balance of sharing and will not direct further sharing here. We are concerned that requiring a sharing of expense (as opposed to a sharing of earnings) could serve an unintended consequence of causing a utility to withhold expense or efforts at restoration, when we believe it is important to promote those efforts to the exigent at the time.[54]

The Commission's decision recognizes both that repair and restoration work is critical to customers during and following emergency events, and that the increasing occurrence of climate-driven disasters like wildfire will continue to result in the need for utilities to restore service quickly and efficiently.

Notably, Staff's sharing proposal rejected in docket UE 394 would have required PGE to absorb 10 percent of wildfire and ice storm repair and restoration costs. Staff's proposal here would have PacifiCorp absorb 70 percent of such costs. Such a drastic disallowance of system restoration costs certainly does not "promote [restoration] efforts" after emergencies like wildfires.

**Q. How does the Company respond to Staff's rationale for its amortization proposal?**

A. When Staff recommends disallowing 70 percent of the Company's wildfire repair and restoration costs, the proposal is supported by a single phrase in one sentence: "In light of court findings, Staff proposes" the 30/70 mechanism. While Staff's analysis is not explained further in testimony, the references earlier in the testimony to the findings in the *James* trial appear to motivate the proposed disallowance.[55] Like other

[53] Docket No. UE 349, Order No. 22-129 at 54.
[54] *Id.*
[55] *See* Staff/1100, Mondragon/50-51 (description of wildfire litigation and settlements).

Staff and intervenor testimony, the amortization proposal treats negligence findings from the *James* district court jury verdict as the equivalent of a prudence finding that is binding on the Commission.[56]

**Q. Is Commission prudence review bound by judicial negligence findings?**

A. No. It is my understanding that a jury's negligence finding does not make a utility action *per se* imprudent, and actions found prudent in a regulatory proceeding are not exempt from being found negligent in a civil trial. The Commission recognized the difference between the two standards when it refused to abate a proceeding to await the results of a civil action alleging negligence against PGE: "Because the applicable legal standards are different in this docket and [the civil case], the outcome of the [civil case] is irrelevant to our determination of whether PGE acted prudently."[57]

**Q. How does this impact Staff's rationale for its 30/70 amortization proposal?**

A. Pointing to a jury's negligence finding, without more, does not demonstrate that the subject utility failed to meet the Commission's prudence standard. "In a prudence review," the Commission explained in a 2017 decision, "we look at the objective reasonableness of a decision at the time it was made considering the information then available to the utility. We examine all actions of the utility – including the process that the utility used to make a decision. We do not require perfection; just that the utility's actions were reasonable."[58] In limited situations, a jury's decision may provide limited information useful to a Commission prudence review, but the

[56] *See, e.g.,* Staff/2200, Brewer, Pileggi, and Stevens/22 ("[i]t seems hardly fair that the gross negligence and misconduct of PacifiCorp should be subsidized by customer … .")
[57] *In the Matter of Portland General Electric Company, Application to Amortize Boardman Deferral,* Docket No. UE 196*,* Order No. 10-051, at 4 (Feb. 11, 2010).
[58] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482, at 6 (Dec. 20, 2016).

Commission still must make independent findings to meet its statutory duties regarding prudence determinations. In this situation, the *James* jury decision referenced by Staff provides no assistance to the Commission because the jury was focused on whether it was reasonable to turn off the power, not whether it was prudent to repair and restore PacifiCorp's system after the wildfire.

In the circumstances surrounding PacifiCorp's restoration efforts after the 2020 wildfires, prudence review should look to whether the Company's restoration actions, and its associated expenditures, were reasonable in the aftermath of the wildfires, as addressed by Company witness Berreth. A jury verdict, especially one that (a) reviews only actions before and during a wildfire regarding whether it was reasonable to leave PacifiCorp's system energized; and (b) was not focused on all the wildfire events associated system restoration; and (c) does not review the Company's repair and restoration expenditures, does not inform the Commission whether the Company's actions in the aftermath of the wildfire to restore service were undertaken reasonably. Without additional evidence, Staff's decision to advocate for a monumental disallowance "[i]n light of court findings," does not withstand analysis and certainly does not constitute a proper finding of imprudence.

**Q. What are the policy implications of Staff's conflation of negligence and prudence standards?**

A. The Commission recently recognized the challenges utilities face when their actions during a wildfire event are subject to scrutiny in jury trials as well as regulatory review by the Commission:

> [W]e emphasize that Oregon needs to find appropriate policy and regulatory solutions to the serious problems wildfire liability creates

> for PacifiCorp and, indeed, all utilities and their customers. The *James* verdicts are an example of the risk utilities may face in adjudication of wildfire actions in civil courts, where juries evaluate whether the company met an unclear and rapidly changing duty of care and engaged in willful misconduct. It may be impossible for a utility to avoid a civil court finding of gross negligence, regardless of actions the utility took.[59]

The Commission recognizes the difficulty in reconciling civil liability standards with the Commission's duty to maintain reliable service offered at just and reasonable rates:

> Maintaining affordable electric service in the face of mounting liability is a problem with which the state as a whole will need to reckon. In doing so, the state must grapple with the appropriate balance between affordability, reliability and reducing-but not completely eliminating-the risk of utility wildfire ignitions, which are just one source among many sources of wildfire ignition.[60]

Pointing to a state court jury verdict (especially one that is on appeal), without further independent analysis, does not provide sufficient evidence to support a finding that the Company acted imprudently, and that its legitimate, documented costs of repairing its system to restore service to its customers after wildfires should be disallowed. A jury empaneled in a civil lawsuit cannot be expected to understand the intricacies of state policy, regulatory principles or utility operations, and should not be deferred to in matters of prudence.

**Q. Does AWEC's recommended disallowance raise similar issues to Staff's proposal?**

A. Yes. AWEC witness Kaufman characterizes the Company's efforts to restore service after wildfires as the result of imprudent management, the costs of which should not

[59] Docket No. UE 428, Order No. 24-155, at 7 (May 30, 2024).
[60] *Id.*

be recovered from customers. AWEC inappropriately recommends disallowance of restoration costs for assets that are now in-service, are used and useful, and will continue to be relied upon to serve customers for years to come. Like Staff, AWEC conflates prudence with a jury's finding of negligence. For the reasons detailed above, relying solely on the negligence findings in a jury verdict without further independent analysis does not provide sufficient evidence to support a finding that the Company acted imprudently or that documented costs of repairing its system to restore service to its customers after wildfires should be disallowed. Company witness Cheung additionally demonstrates that the manner in which AWEC structures its adjustment constitutes not only disallowance but an unwarranted penalty against the Company.

**Q. Are there other issues on which the parties' testimony incorrectly characterizes the Company's actions based on civil litigation outcomes?**

A. Yes. Staff points to dividend payments made by the Company to its shareholder Berkshire Hathaway Energy (BHE), and suggest the dividends be retroactively disgorged and used to support the CFF proposed in Company witness Steward's testimony.[61] Staff acknowledges that the Company did not pay a dividend to BHE in 2020, the year of the Labor Day fires, and notes that the Company suspended all dividends to BHE in 2023 after the first *James* jury verdict.[62] Nevertheless, Staff argues PacifiCorp should not have issued dividends in any year after the Labor Day fires. Staff argues that "it seems hardly fair that the gross negligence and misconduct

[61] Staff/2200, Brewer, Pileggi, and Stevens/14.
[62] *Id.*

of PacifiCorp should be subsidized by its customers while over half a billion dollars of dividends went to [BHE]."[63]

Staff's approach and proposal are misguided for three reasons. First, the Company has been through a general rate case since the 2020 wildfires, docket UE 399, and the Commission did not question its distribution of dividends in that proceeding. If dividends should have been permanently prohibited after 2020, the Commission could have implemented that policy in that rate proceeding. Of course the Commission did not impose such a requirement because, like the Company, it did not know the outcome of the *James* class action or the liability amounts that would arise from the June 2023 *James* verdict. It is only through the exercise of hindsight that Staff urges that returns on investment in 2021 to 2023 should be essentially reversed. Staff urges the Commission to adopt an order that would take retroactive, rear-view mirror ratemaking to an unprecedented extreme.

Second, the only basis for Staff's position is its apparent embrace of the negligence findings of the *James* jury as a way to disallow BHE from receiving returns on its investment in the Company. Staff has not conducted independent analysis or even attempted to engage in a prudence analysis regarding the Company's actions. If it had, Staff might not so easily dismiss the Company's 2020, 2023, and ongoing suspension of dividends to BHE. As discussed above, a jury's negligence finding does not substitute for an analysis of the reasonableness of a utility's actions.

Third, Staff is incorrect in claiming that the Company is "profit-taking" as it "continues to accrue massive, unplanned liabilities with no clearly defined plan to

[63] *Id.* at 21.

address such liabilities."[64] PacifiCorp has documented in this case and elsewhere the steps it is taking to contain and reduce wildfire liabilities. The Company has entered into numerous settlements to resolve reasonable liability claims and continues to work productively with other claimants.[65] In this and other Commission proceedings, the Company has made proposals to address the increasing risk of "massive, unplanned" liabilities resulting from wildfires. The Company works with the Commission on Wildfire Mitigation Plans and invests in vegetation management and system hardening to mitigate ignition risk. It has proposed the ICA, the CFF, and liability limitations as means of accruing fewer liabilities in the future. PacifiCorp has not made a "willful choice to increase the risks and burdens faced by customers," as Staff asserts.[66] Rather, the Company works daily to provide safe and reliable service in the face of mounting wildfire liability risk, continue to attract sufficient investment by offering its shareholder a return (when dividends are not, as they are now, suspended), and work with the Commission and policymakers to grapple with the challenges that arise from unbounded wildfire liability.

**Q. How do you respond to Staff's and CUB's arguments that BHE exists to provide "deep pockets" to cover the Company's liabilities?**

A. CUB's testimony asks, "What is the role of BHE?" CUB witness Jenks' answer: "Deep pockets."[67] CUB asserts that "having this financial behemoth behind them allows PacifiCorp access to equity capital as needed and assures debt issuers the

[64] *Id.* at 16.
[65] The Company's efforts to settle liability claims were detailed in its responses to parties' discovery in this proceeding and the Securities and Exchange Commission and other public filings referenced therein.
[66] *Id.*
[67] CUB/100, Jenks/43.

company is strong and stable."[68] Staff notes that BHE has made "significant cash infusions" in PacifiCorp, and the Company has yielded a profit to its owner and investor.[69] CUB and Staff make these points in arguing the Company must bear a disproportionate burden of addressing wildfire risk.

The events of the last year demonstrate the shallowness of CUB's and Staff's analysis. Liability issues have threatened PacifiCorp's credit ratings and overall financial stability. Investors and ratings agencies, who are well aware that BHE owns PacifiCorp, have nevertheless expressed grave concerns about the circumstances the Company and other western utilities face regarding wildfire liability. Moreover, the financial support of a strong owner is not, as Staff and CUB imply, a permanent condition. If wildfire liability risk continues to drive the financial health of Oregon utilities, investors who seek the type of regulated, fair returns (rather than indefinitely suspended dividends) may reconsider their levels of interest in their investments in our state and our industry.

## B. Docket UM 2301: Amortization of Deferred Wildfire Insurance Costs

**Q. Please describe the deferral approved by the Commission in docket UM 2301.**

A. In docket UM 2301, the Commission approved "the Company's application for deferral of increased insurance costs related to wildfires for the twelve months beginning August 21, 2023."[70] The deferral request was prompted when the Company was faced with "commercial insurance costs for the total company [increasing] from

[68] *Id.*
[69] Staff/2200, Brewer, Pileggi, and Stevens/17.
[70] *In the Matter of PacifiCorp, dba Pacific Power, Application for Authorization of Deferred Accounting Related to Insurance Costs for Wildfires*, Docket No. UM 2301, Order No. 24-021, Appendix A, at 7 (Jan. 24, 2024). (hereinafter, UM 2301 Order).

$29 million currently in rates to $125 million (a $96 million increase) for the policy period starting August, 15, 2023."[71] The Commission's deferral decision acknowledged the financial challenges facing the Company, which were exacerbated by the extraordinary increase in commercial insurance premiums:

> The Company predicts the impact of the increased insurance premiums to be approximately 100 basis points compared to its current financial results. What makes this deferral unique is that the Company recently made a $1.9 billion pretax accrual, related to pending wildfire litigation expenses, which resulted in Moody's Investors Services downgrading the Company's senior unsecured rating from A3 to Baa1. With this additional information, Staff determined that the aggregate effect of the circumstances described above and the insurance cost increase poses a threat to the financial security of the Company.[72]

Accordingly, the Company is seeking recovery of the incremental insurance premiums from its most recent policy renewal in August 2023 that are in excess of its currently approved rates established in the 2022 rate case.[73] The Company seeks amortization of its increased excess liability insurance costs over a three-year period through the ICA. The direct and reply testimony of Company witness Coleman provide the information supporting recovery of the increased commercial insurance costs in rates.

**Q. Please describe the proposals in testimony for adjustments to the docket UM 2301 insurance expense amortization.**

A. Staff recommends that the Company be allowed to only recover the amount of insurance expense currently authorized in rates in docket UE 399 and continue to

[71] *Id.*, Appendix A, at 5.
[72] *Id.* at 4.
[73] *In the matter of PacifiCorp, dba Pacific Power, Application for Authorization of Deferred Accounting Related to Insurance Costs for Wildfires*, Docket No. UM 2301, Order No. 24-021 (Jan. 24, 2024).

track excess liability insurance premiums through the deferral authorized in docket UM 2301.[74] Staff also recommends that the deferred expenses "be shared 20 percent by the utility and subject to an earnings test, as discussed in Staff Witness Peterson's testimony."[75] It appears Staff also applies the proposed 20 percent sharing to the amount of insurance currently in rates.[76] However, Staff witness Peterson's testimony does not appear to include an earnings test, but recommends that the "Company share in the excess insurance costs in the amount of 20 percent," and states that "[t]he 20 percent share for PAC is proposed for two reasons: to incentivize the Company to purchase in a least cost manner, and [t]o recognize that the 2020 fires play a role in the increase in insurance costs."[77]

**Q. How does the Company respond to Staff's recommendation?**

A. Staff's recommendation should be rejected for several reasons. First, Staff's proposal, if adopted, creates concerning precedent as it is not only denying PacifiCorp recovery of prudently incurred costs that were the subject of the deferral in docket UM 2301 but it also denies the Company timely recovery of the excess liability insurance that the Company will need to purchase in order to protect itself and its customers from wildfire risk. Staff provides no basis for its proposal. The amount Staff proposes to include in this rate case for on-going liability insurance premiums is only 80 percent of the 2021-22 premiums that are currently included rates through docket UE 399. Furthermore, similar to Staff's recommendation to disallow wildfire restoration costs,

[74] Staff/1900, Stevens/40.
[75] *Id.*
[76] Staff witness Stevens' workpapers appears to apply the 80/20 sharing proposal to insurance costs currently in rates.
[77] Staff/1600, Peterson/25-26.

Staff's 20 percent "sharing" proposal is based entirely on conclusory statements that do not withstand analysis. Staff argues that its 20 percent disallowance of insurance premiums paid in 2023-24 will "incentivize the Company to purchase in a least cost manner."[78] This purported "incentive" ignores the reality of the market for wildfire insurance that PacifiCorp detailed in docket UM 2301 and in testimony in this proceeding. The extraordinary increases in wildfire insurance premiums for PacifiCorp were documented in docket UM 2301, as was the impact of those increased costs on the Company's financial stability. Moreover, Staff provides no citation to authority that supports the principal that insurance premium costs incurred by a utility should be disallowed, in whole or in part, as a basis for setting just and reasonable rates. I am aware that the California Public Utilities Commission has previously rejected similar arguments, stating: "[t]he Commission has consistently authorized rate recovery of wildfire liability insurance premium costs as a standard cost of service and has never accepted intervenor arguments that incurred premium costs should be disallowed, in whole or in part, to shareholders."[79]

If PacifiCorp could purchase excess liability insurance covering wildfire events at a lower cost and still obtain prudent levels of coverage, it would. In fact, the Company has always sought out the most affordable insurance coverage, and its premium payments have regularly been found reasonable in Commission rate reviews.[80] The Company has no incentive to pay more to insurers than required. A

[78] *Id.* at 25.
[79] Public Utilities Commission of the State of California, *Application of Southern California Edison Company (U338E) for Authorization to Recover Costs Related to 2018-2020 Wildfire Insurance Premiums Recorded in its Wildfire Expense Memorandum Account*, Application No. 19-07-020, Decision No. 20-09-024 (Sept. 9, 2020).
[80] *See, e.g., In the Matter of PacifiCorp, dba Pac. Power, Request for a Gen. Rate Revision*, Docket No. UE 374, Order No. 20-473 at 108 (Dec. 18, 2020) ("We find that PacifiCorp has demonstrated that its proposed level of expense for insurance is reasonable and decline to adopt Staff's disallowance.").

disallowance of the payments it must make for adequate coverage does not incentivize least cost purchasing. Rather, if anything, it incentivizes the purchase of less insurance than may be needed, at exactly the time when increasing wildfire risk and skyrocketing costs make obtaining adequate insurance coverage critical to the Company and its customers. Moreover, Staff's proposal does not constitute "sharing" of the risks and benefits of insurance coverage with customers. Company witness Steward addresses Staff's "sharing" proposal as it impacts current and future insurance expenses, and explains that Staff's proposal is at odds with the workings of insurance coverage apply with equal force to the amortization of the insurance costs deferred in docket UM 2301.

**Q. How does the Company respond to Staff's argument that its proposal "recognize[s] that the 2020 fires play a role in the increase in insurance costs?"**

A. Staff argues that sharing of insurance expense "recognizes that the 2020 fires play a role" in the deferred insurance expense. When asked in discovery to clarify, Staff witness Peterson states: "Staff's view that the 2020 fires have played a role in the increase in insurance premiums is informed by the significance of these fires to Oregon as a whole and to PacifiCorp specifically, and the effect PacifiCorp stated wildfires have on the liability insurance premiums deferred in docket UM 2301."[81] Standing alone, this conclusory statement provides no basis for sharing or disallowance: the fact that the 2020 fires occurred and presumably affected the insurance market provides no justification for disallowing 20 percent of the Company's cost of 2023-24 excess liability premiums. Quite the opposite is true.

[81] PAC/2401.

Since wildfire liability risk is increasing, the Company should prudently purchase insurance to mitigate the risk. Just as the Company must pay market rates for fuel, supplies, and other expenses, its prudent expenses on insurance should be fully recoverable. Otherwise, the Commission would impose an arbitrary disallowance of expenses increasingly important to protect the Company and its customers.

On the other hand, if Staff is implying that the higher 2023-24 insurance premiums are a result of findings in civil lawsuits against PacifiCorp, Company witness Coleman's reply testimony explains why, from an insurance coverage perspective, Staff's supposition is unsupported.[82]

In that case, Staff's recommendation suffers from the same infirmity as its proposal on the docket UM 2116 repair and restoration amortization. Staff conflates a jury's negligence finding with a finding of imprudence. As discussed earlier in my testimony, equating negligence and prudence standards is an error. The Commission should not approve findings of imprudence, and associated disallowances, simply based on a party pointing to a civil jury decision. A "sharing" disallowance is even less appropriate here where Staff points not to any finding of negligence, imprudence, or anything else justifying disallowance. Rather, Staff's recommendation relies only on its unsupported opinion that "the 2020 fires play a role" in the increases in the Company's insurance expense.

Company witness Coleman provides a further response to Staff's claim that the referenced 2020 fires played a role in the deferred amount of insurance premiums recorded under docket UM 2301.

[82] PAC/2400, Coleman.

**Q. How does PacifiCorp respond to CUB's assertion that the deferral approved by the Commission in docket UM 2301 violates the docket UE 399 "stay out" agreement?**

A. CUB witness Jenks states that when the Commission approved the insurance expense deferral in docket UM 2301, "it was contested on whether it could overcome the deferral exception thresholds established in the UE 399 stay-out agreement."[83] The Company agrees CUB and AWEC contested the deferral, but ultimately "CUB and AWEC stated they would not oppose a Staff recommendation to approve the deferral."[84] The Commission approved Staff's recommendation in docket UM 2301, which included analysis demonstrating that the insurance expense deferral was subject to an exception to the stay-out agreement, finding that "the dollars involved in this deferral request is material given that it represents roughly 100 basis points and PacifiCorp does face significant financial risks."[85]

**Q. Does CUB offer reasons the Commission should not amortize the full deferral amount approved in docket UM 2301?**

A. CUB states that "before amortization, the Commission needs to address the prudence of these costs, apply an earnings test, and decide whether the costs should be subject to sharing."[86] CUB does not offer a proposed earnings test, a sharing mechanism, or facts that question the prudence of the Company's insurance expenditures. The testimony of Company witness Coleman demonstrates that the Company's

[83] CUB/100, Jenks/78. The "stay out" agreement is included in a stipulation approved by the Commission in the Company's most recent general rate case. *See In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 399, Order No. 22-491, Appendix C, at 12-13 (Dec. 16, 2022) (Stipulation approved by the Commission that includes the stay-out provision).
[84] UM 2301 Order, Appendix A, at 4.
[85] *Id*.
[86] CUB/100, Jenks/78-79.

expenditures on the deferred 2023-24 insurance premiums were prudent and reasonable and should be amortized over three years as part of the Commission's order in this proceeding.

## V. LOW-INCOME DISCOUNT, DISCONNECTIONS, STAKEHOLDER INPUT

### A. Low-Income Discount

**Q. Several parties raised concerns regarding the potential impact of this case on customers with lower incomes who may already face difficult burdens from their energy costs. Does PacifiCorp have programs to support those customers?**

A. Yes. PacifiCorp is very aware of the energy burdens some customers face and has put programs in place to mitigate those burdens, including its Low-Income Discount (LID).

**Q. What is the LID?**

A. As I summarized in my direct testimony, the LID is a program through which income-qualified residential customers receive a monthly bill discount at one of two levels based on the customer's household income as a percentage of Oregon SMI adjusted to household size.[87] Customers with household incomes up to 20 percent of SMI will receive a 40 percent discount on their electricity bill and customers with household incomes between 21 percent and 60 percent of SMI will receive a 20 percent discount on their electricity bill.

[87] Exhibit PAC/200, McVee/16.

**Q. Do other PacifiCorp witnesses address parties' recommendations relating to PacifiCorp's LID, disconnections and arrearages?**

A. Yes. Company witness Meredith responds to parties' testimony on PacifiCorp's LID, disconnections, and arrearages in his reply testimony. I discuss PacifiCorp's recommendation to refine its low-income programs after the Company's Energy Burden Assessment (EBA) is complete. I also address parties' testimony on PacifiCorp's EBA and solicitation of input from impacted stakeholders.

**Q. Staff and the Coalition recommend several adjustments to the Company's LID. Do you have any general responses to the parties' proposals?**

A. Yes. PacifiCorp believes that any changes to the LID program should take place after the Company's EBA is complete, which is expected October 1, 2024. The EBA will assess how effective the LID is at reducing energy burden, identify gaps in assistance, and provide recommendations for achieving lower energy burden targets. Company witness Meredith responds to each of Staff's proposals in detail in his testimony.

Moreover, as Staff acknowledges, "It is difficult to make a fully fleshed out proposal on such a sensitive and impactful matter without the engagement of a full table of stakeholders, including community members, advocates, and the utility."[88] While PacifiCorp continues to improve its LID through coordination with stakeholders, such a complex and far-reaching issue may be difficult to address in the confines of this GRC.

Staff's final recommendation on this issue is that "the Company should plan to engage with Staff and stakeholders throughout the UM 2211 process and allow for

[88] Staff/300, Scala/24-25.

additional learnings and evolutions to existing and future features of the Company's LID and energy assistance offerings."[89] The Coalition similarly acknowledges that a "long-term approach to low-income ratepayer discounts may be better evaluated in Docket No. UM 2211."[90] PacifiCorp is committed to continue refining its LID program through docket UM 2211.

**Q. You mentioned PacifiCorp's anticipated EBA. In its testimony, Staff invites PacifiCorp to provide an equity assessment of rate case impacts on differently burdened residential communities in PacifiCorp's service territory.[91] How do you respond?**

A. PacifiCorp has engaged a third party to prepare an EBA for the Company's service territory. PacifiCorp will use the results of that EBA to help inform future decision making for the Company's energy burden related programs.

**Q. Regarding the EBA, the Coalition recommends that PacifiCorp should rely on actual customer data based on surveys of LID customers and not overly rely on census tract or other more general data sources.[92] How do you respond?**

A. PacifiCorp has completed a detailed survey of its LID customers. In 2023, PacifiCorp ran two waves of program surveys, one in May and the other in October and November. PacifiCorp plans to run a Wave 3 survey in October 2024. In the first two surveys, PacifiCorp surveyed 1,536 customers and 2,135 customers, respectively. Of note, the Company's survey of LID participants indicates that the program is presently having a significant impact on energy burden.

[89] Staff/300, Scala/26.
[90] Coalition/100, Fain-Segovia Rodriguez-Daryanani/Page 21.
[91] Staff/300, Scala/9.
[92] Coalition/100, Fain-Segovia Rodriguez-Daryanani/11-13.

**Q. The Coalition also recommends that PacifiCorp use the "Self Sufficiency Standard" in its EBA.[93] How do you respond?**

A. This proposal raises significant issues regarding regulatory policy that should not be addressed in an individual utility's rate case, but rather docket UM 2211.

**Q. CUB similarly recommends that PacifiCorp expand and improve its customer data collection to measure both process and outcomes surrounding the Company's low-income programs.[94] How do you respond?**

A. As discussed in Company witness Meredith's testimony, PacifiCorp is willing to continue having discussions with the Commission and parties to improve its LID. But it should be noted that the Company has issued a detailed survey of its LID customers and received generally positive feedback. The results of those surveys showed that a vast majority of respondents are satisfied with the program.

**B. <u>Disconnections</u>**

**Q. Various parties also raised concerns about disconnections. How does PacifiCorp approach customer disconnections?**

A. PacifiCorp's detailed process for disconnections is included in the Company's Commission-approved tariffs.[95] When a customer fails to pay the amount due, the Company provides a past due notice at least 20 days before terminating service and attempts to contact the customer again at least five business days prior to termination of service. When speaking to the customer, PacifiCorp informs the customer of all

[93] Coalition/100, Fain-Segovia Rodriguez-Daryanani/12-13.
[94] CUB/200, Wochele-Jenks/60.
[95] PacifiCorp's Oregon Tariff, Rule 11A.

appropriate rights and options established by orders of the Commission, including a Time Payment Agreement.

PacifiCorp does not include in its tariffs a disconnect charge, which avoids increasing the burden disconnected customers face. Additionally, PacifiCorp can promptly reconnect disconnected customers after those customers contact the Company and take the necessary actions for reconnection. PacifiCorp complies with all Commission rules governing reconnection, and the Company's customer service managers are allowed flexibility on a case-by-case basis to work with a customer to reconnect under parameters that are more lenient than the Commission's rules, given the nature of the customer's circumstances.

**Q. CUB testifies that PacifiCorp's disconnections for non-payment have "increased dramatically" since 2021.[96] Is that accurate?**

A. While the number of disconnections has increased, there is important context to consider. First, the increase in disconnections is the result of resuming disconnections following COVID-19 pandemic moratoriums. When the pandemic moratoriums were lifted, arrearages significantly increased. PacifiCorp also identified and corrected a system issue that had prevented some accounts from being identified for disconnection.[97] Working through the backlogs has increased the number of disconnections.

[96] CUB/100, Jenks/6.
[97] CUB DR 184.

**Q. CUB recommends that PacifiCorp expand its disconnection data collection to include customer and neighborhood level demographics to ensure evidence-based targeting of mitigation.[98] Should the Company provide this data?**

A. As part of its Clean Energy Plan (CEP), PacifiCorp has already included community benefit indicator (CBI) metrics to track disconnections. PacifiCorp also has a CBI metric to track energy burden by census tract for low-income customers, bill assistance participants, and Tribal members. That is the appropriate process to evaluate these requests, with proper coordination with the Community Benefits and Impacts Advisory Group (CBIAG) and stakeholder outreach.

## C. Input from Stakeholders

**Q. Staff invites PacifiCorp to explain how environmental justice input was solicited and applied in this case, including participation from the CBIAG.[99] How do you respond?**

A. PacifiCorp collaborated extensively with stakeholder groups, including CBIAG, as part of the Company's CEP engagement to assess the most pressing concerns relating to the Company's transition to cleaner energy. These engagements built on the lessons learned from PacifiCorp's community engagement relating to its DSP. PacifiCorp's stakeholder engagement spaces have adapted and will continue to adapt to foster inclusion, accessibility, and collaboration for their diverse participating audiences. Through an extensive survey process, PacifiCorp identified that costs and potential bill increases are the primary concerns with the transition to cleaner energy. The

[98] CUB/200, Wochele-Jenks/60.
[99] Staff/300, Scala/9.

dependability of renewable sources and the potential impact of materials required for clean energy technology also concern more than half of the surveyed participants.

In addition to these CEP processes, PacifiCorp incorporates public input in its integrated resource plan (IRP) preparation. PacifiCorp's system IRP, and its associated public input meeting process, addresses the broad system approach. More recently, PacifiCorp added the CBIAG which focuses on equity and inclusion matters.

PacifiCorp also solicited input from customers relating to the Company's transportation electrification efforts. PacifiCorp held three virtual forums with industry stakeholders and six local workshop sessions in 2022. PacifiCorp also implemented a Tribal Nations Engagement series, which supports and fosters collaboration, consultation, and shared understanding of Federal, State and local programs, policies, and grants for the Oregon Tribal Nations.

PacifiCorp's CBIAG was established in October 2022 and brings together a diverse group of members representing environmental justice communities, community-based organizations, and community representatives, offering support services and diverse perspectives of community members residing within the service districts of which PacifiCorp serves. The CBIAG focuses on equity and a clean energy future in the state of Oregon in accordance with HB 2021. Through the CBIAG, PacifiCorp plans to continue seeking direct stakeholder feedback to build an inclusive and accessible process for consultation and collaboration.

PacifiCorp works in collaboration with the CBIAG to identify barriers to participation and how to address these barriers. External tools which have been developed and shaped with input and serve to support the CBIAG include:

development of an online information hub to support access to meeting content; program content and filing updates in both Spanish and English; customer facing program and informational materials; and the Clean Energy Benefit Survey, which informs the CBIAG.

PacifiCorp incorporated discussions from these engagement processes into its CBI. One of the Company's CBIs is focused on health and community well-being. To monitor this CBI, PacifiCorp tracks the number of residential customer disconnections by census tract.

PacifiCorp has also focused on incorporating energy equity into its planning and ratemaking. Energy equity is the concept that all members of society should be able to afford and have access to a necessary and basic supply of energy. PacifiCorp aims to mitigate and not disproportionately allocate costs to highly impacted communities and vulnerable populations. As part of its efforts to address energy equity, PacifiCorp has begun measuring average energy burden within each census tract in Oregon.

**Q. Relatedly, CUB testifies that PacifiCorp should ensure that equity considerations in its operations and planning are translating into measurable and tangible benefits for customers[.]"[100] How do you respond?**

A. This is a key component of the CEP, specifically the CBIs and CBI metrics. The CBIs and CBI metrics are expected to evolve over time based on input from the CBIAG and other stakeholders.

[100] CUB/200, Wochele-Jenks/60.

**Q. Staff indicates in its testimony that it intends to fully evaluate and conduct a prudence review of the management of the self-perform and demand response programs in the appropriate proceeding.[101] How do you respond?**

A. It is not clear what concerns Staff has with PacifiCorp's self-perform and demand response programs. These self-perform and demand response programs in Oregon are funded through Schedule 291, System Benefits Charge, which is not part of this proceeding. That Schedule 291 funding and the related programs are addressed through advice letter filings rather than a GRC. Staff appears to suggest that it intends to raise these issues in a different proceeding, and PacifiCorp will look to address any concerns Staff may raise in those proceedings.

## VI. JIM BRIDGER CONVERSION

**Q. Has CUB proposed a prudence disallowance for the gas conversion at Jim Bridger Units 1 and 2?**

A. Yes. Without any discussion of the need for the resource, the project's economics, or the relevant stipulations from the last rate case (which CUB joined),[102] CUB asks the Commission to find the Jim Bridger Unit 1 and 2 gas conversion imprudent.[103] CUB proposes that the Commission either disallow 10 percent of the rate base associated with the investment (approximately $1 million in this case), or reduce the annual depreciation of the plant by $464,000 to reflect the end of the plant's ability to serve Oregon in 2030.[104]

[101] Staff/700, Dlouhy/18.
[102] Docket No. UE 399, Order No. 22-491, Appendix C at 5.
[103] CUB/100, Jenks/22.
[104] CUB/100, Jenks/26-28.

**Q. What is the basis for CUB's proposed disallowance?**

A. CUB claims that the units should have been retired, not converted, because the gas conversion is inconsistent with HB 2021.[105]

**Q. Is the gas conversion at Jim Bridger Units 1 and 2 now complete?**

A. Yes. The conversion was completed in the spring of 2024 as scheduled and the units are now fully dispatchable.[106]

**Q. Is the gas conversion significantly more beneficial to customers than retirement?**

A. Yes. As outlined in the direct testimony of Company witness Thomas R. Burns, the conversion of these units helps cost-effectively meet a significant and increasing need for capacity. The cost of gas conversion is relatively modest—$34.6 million total-Company or $9.3 million Oregon-allocated—and the conversion demonstrates substantial benefits to customers in all price-policy scenarios.[107]

**Q. Would retirement of these units instead of gas conversion place upward pressure on rates?**

A. Yes. CUB's recommendation to retire Jim Bridger Units 1 and 2 instead of converting them to gas would have increased the Company's cost to serve Oregon customers. CUB's position on this issue is directly at odds with its overarching concerns about affordability.

[105] CUB/100, Jenks/25.
[106] OPUC DR 460.
[107] PAC/900, Burns/2, 13.

**Q. Is the effect of CUB's proposed adjustments to accept the benefits of the Jim Bridger Unit 1 and 2 gas conversion without paying the full costs of attaining these benefits?**

A. Yes. The benefits of the Jim Bridger gas conversion are reflected in reduced NPC in the TAM, reduced operation and maintenance (O&M) costs in this case, and increased system reliability, and CUB is a party to the stipulation in this year's TAM proceeding. CUB's proposal in this proceeding violates the matching principle by accepting the full benefits of the Company's investment in the Jim Bridger gas conversion without paying the full costs of this investment.

**Q. CUB points to the Commission's order on the Company's 2023 IRP and CEP issued *after* the filing of this case as the basis for claiming that Jim Bridger's conversion is inconsistent with HB 2021.[108] By relying on these orders, is CUB applying an improper hindsight review of the decision to convert these units?**

A. Yes. The Commission's decision on the Company's 2023 IRP and CEP was issued in March 2024 when construction on the projects was near completion and cannot be considered in determining the reasonableness of the Company's earlier decision to convert the Jim Bridger units. In any event, there is nothing in this order that states or implies that the Company should not pursue the Jim Bridger gas conversion.

[108] *In the Matter of PacifiCorp, dba Pacific Power, 2023 Integrated Resource Plan*, Docket LC 82, Order No. 24-073 (Mar. 19, 2024).

**Q. Is the Commission's acknowledgement of this resource in the 2021 IRP the relevant decision for this prudence review**?

A. Yes. In May 2022, the Commission acknowledged the Jim Bridger gas conversion in the 2021 IRP.[109]

**Q. Did the Commission consider HB 2021 when reviewing the Jim Bridger conversion in the 2021 IRP?**

A. Yes. Although it is my understanding that HB 2021 by its terms applies only to IRPs submitted after January 1, 2022,[110] Staff expressly considered HB 2021 in its analysis of the Company's 2021 IRP.[111]

**Q. CUB argues that the Company's assumptions around carbon pricing in the 2021 IRP now seem unlikely and call into question the analysis of HB 2021 and the Jim Bridger gas conversion in that IRP.[112] Please comment.**

A. This is another example of CUB improperly applying a hindsight review to judge the prudence of the Company's decision-making. Nevertheless, it is important to note that in the economic analysis presented by Company witness Burns, the Jim Bridger gas conversion was cost effective under all policy scenarios, including those assuming no carbon price.[113]

[109] *In the Matter of PacifiCorp, dba Pacific Power, 2021 Integrated Resource Plan*, Docket No. LC 77, Order No. 22-178 (May 23, 2022).
[110] ORS 469A.415(3)(a).
[111] Docket No. LC 77, Order No. 22-178, Appendix C at 3, 36-37.
[112] CUB/100, Jenks/23.
[113] PAC/900, Burns/13.

**Q. CUB also asserts that when the Commission acknowledged the Jim Bridger gas conversion in the 2021 IRP notwithstanding the increased emissions compared to closing the plant, the Commission's conclusion was based in part on analysis from Commission Staff that "other, more cost-effective approaches to GHG reduction should be preferred." According to CUB, PacifiCorp is not implementing those other greenhouse gas (GHG) reductions "at a level that will help Oregon achieve its GHG requirements."[114] Please respond.**

A. CUB's testimony fails to consider the generation resources that PacifiCorp has acquired in recent years that reduce the Company's GHG emissions, and its plans for acquiring additional complying resources. Since 2020, PacifiCorp has added significant new wind resources that resulted in 329,418 megawatt-hours of additional wind generation. In 2024 PacifiCorp is adding 1,163 MW of incremental system wind, and another 400 MW of incremental system wind in 2025. In 2026, PacifiCorp will add 400 MW of incremental solar, and 400 MW of incremental battery storage capacity. And PacifiCorp is in advanced negotiations with third parties developing 755 MW of battery storage capacity that can come online by summer of 2026. PacifiCorp also plans to propose specific procurement actions in the 2025 IRP to further address its need for additional resources.

**Q. What other Commission decisions are relevant to this prudence review?**

A. In PacifiCorp's last general rate case, docket UE 399, the Commission addressed the Jim Bridger gas conversion in approving two partial stipulations, both of which CUB

[114] CUB/100, Jenks/23.

supported. In Order No. 22-491 issued in December 2022,[115] the Commission approved the Second Partial Stipulation extending the depreciable lives of Jim Bridger Unit 1, Unit 2, and Common Lives to December 31, 2029, "reflecting the conversion of Units 1 and 2 to natural gas-fired resources in 2024 consistent with PacifiCorp's acknowledged 2021 Integrated Resource Plan."[116] This agreement reduced revenue requirement in docket UE 399 by approximately $12 million. The Commission also approved the Third Partial Stipulation modifying the Jim Bridger Unit 1 exit order so that it applied only to the unit if it was a coal-fired unit.[117] The Commission's approval of these stipulations—with CUB's support—facilitated the conversion of the Jim Bridger units, provided an immediate benefit to customers by reducing depreciation expense in rates, and is further evidence that, at the time the Company made the decision to move forward with the conversion of the Jim Bridger units, it acted reasonably.

**Q. CUB claims that gas conversions are inefficient and problematic for serving Oregon load in light of HB 2021's emissions constraints.[118] Please comment.**

A. CUB's policy arguments around the best resource choices for Oregon—balancing cost and HB 2021 compliance—belong in current and future IRP and CEP dockets, not in a prudence review of an already-acknowledged resource.

[115] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision,* Docket No. UE 399, Order No. 22-491 (Dec. 16, 2022).
[116] Docket No. UE 399, Order No. 22-491, Appendix B at 5.
[117] Docket No. UE 399, Order No. 22-491, Appendix C at 7.
[118] CUB/100, Jenks/24.

**Q. CUB's proposed disallowances are based on the premise that these Jim Bridger gas units may not be used and useful in Oregon after 2030.[119] Please respond.**

A. CUB claims that it is "in doubt" whether these resources will be used and useful in Oregon after 2030 because HB 2021 requires an 80 percent reduction in emissions by that time. CUB's adjustment is explicitly speculative, asking the Commission to disallow costs now because of how it might impact HB 2021 compliance in six years. In acknowledging the Jim Bridger conversion in the 2021 IRP, the Commission accepted Staff's analysis that retirement of Jim Bridger was not the most cost-effective option for achieving emissions reductions.[120] CUB is second-guessing that analysis without providing any analytical support to the contrary.

## VII. EXIT ORDERS FOR COAL GENERATION FACILITIES

**Q. Is PacifiCorp removing certain coal facilities from Oregon rates?**

A. Yes. Consistent with Oregon Senate Bill (SB) 1547, PacifiCorp intends to remove coal resources from Oregon rates by 2030.

**Q. Has PacifiCorp agreed to dates by which specific coal resources will be removed from Oregon rates?**

A. Yes. In PacifiCorp's two preceding GRCs, the Commission approved Exit Orders for several PacifiCorp coal facilities. The Commission initially adopted Exit Orders for Cholla Unit 4, Jim Bridger Unit 1, Craig Units 1 and 2, Naughton Units 1 and 2, Colstrip Units 3 and 4, and Dave Johnston Units 1-4 in PacifiCorp's 2021 GRC.[121] In the Company's 2023 GRC, the Commission approved a stipulation that delayed the

[119] CUB/100, Jenks/27.
[120] Docket No. UE 399, Order No. 22-491 at 6-7.
[121] Docket No. UE 374, Order No. 20-473 at 12.

exit date for Craig Unit 2 to September 30, 2028, and adopted Exit Orders for Hayden Units 1 and 2 with exit dates of December 31, 2028, and December 31, 2027, respectively.[122] That same stipulation also modified the Jim Bridger Unit 1 Exit Order to specify that the exit date will apply to that unit only as a coal-fired unit. The current Commission-approved PacifiCorp exit dates for PacifiCorp's coal-fired units are listed in Table 1 below.

**Table 1: Commission-approved coal unit exit dates.**

| | |
|---|---|
| Cholla Unit 4 | December 31, 2020 |
| Jim Bridger Unit 1 | December 31, 2023 |
| Craig Unit 1 | December 31, 2025 |
| Craig Unit 2 | September 30, 2028 |
| Naughton Units 1 and 2 | December 31, 2025 |
| Colstrip Units 3 and 4 | December 31, 2027 |
| Dave Johnston Units 1-4 | December 31, 2027 |
| Hayden Units 1 | December 31, 2028 |
| Hayden Unit 2 | December 31, 2027 |

**Q. You discussed the Jim Bridger gas conversion above. Does that conversion mean that the previously approved exit date no longer applies for Jim Bridger Unit 1?**

A. Yes. According to Order No. 22-491 issued in docket UE 399, the Exit Order applies only if Jim Bridger Unit 1 is a coal-fired facility. Jim Bridger Unit 1 is now a gas-fired facility with a forecast retirement date of 2037.[123]

[122] Docket No. UE 399, Order No. 22-491, Appendix C at 7.
[123] PacifiCorp's 2023 IRP Update at 13 (Apr. 1, 2024) (available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023_IRP_Update.pdf) (last visited July 15, 2024).

**Q. Has PacifiCorp's forecast retirement dates for other facilities changed since the Commission last approved the Company's exit dates?**

A. Yes. Naughton Units 1 and 2 are scheduled for conversion to natural gas and PacifiCorp now forecasts those units retiring in 2036. Additionally, Colstrip Unit 3 will now be retired in 2025, while the forecast retirement date for Colstrip Unit 4 has been extended to 2029. Finally, the forecast retirement date for Dave Johnston Units 1 and 2 has been delayed to 2039.

**Q. Has AWEC raised various issues regarding PacifiCorp's coal exit dates?**

A. Yes. While the Company did not include any proposals on exit dates in its filing, AWEC witness Kaufman recommends several adjustments to PacifiCorp's Exit Orders. Many of his adjustments propose to align the Commission-approved exit dates with PacifiCorp's current forecasted retirement dates. AWEC witness Kaufman also recommends revoking the Exit Orders for Naughton Units 1 and 2, since those units will be converted to natural gas, and for that reason may remain in Oregon rates after 2030.[124]

**Q. Do you have a general response to AWEC's proposals?**

A. Yes. Many of AWEC's proposals seem premature as the Company reviews and responds to fast-changing regional and industry developments, including increasing demand, resource adequacy concerns, and higher market costs, and changing Company circumstances including more limited access to capital and the direction of the multi-state process for cost allocation. The Company is actively considering many of these issues in its current 2025 IRP and CEP processes.

[124] AWEC/200, Kaufman/9.

**Q. Do you agree with AWEC that (1) the Commission should align Oregon's exit dates with the Company's updated forecast retirement date for units with retirement dates that precede 2030; (2) the depreciable life of plants with Exit Orders be aligned with the dates of the Exit Orders; and (3) the depreciable life of gas converted plants be aligned with the economic life used to justify the prudence of conversion?[125]**

A. No. As evidenced by the changes to PacifiCorp's forecast retirement dates and depreciable lives that AWEC witness Kaufman discusses in testimony, these dates are not set in stone. As resource demand is increasing and resource adequacy issues continue to arise, PacifiCorp is studying a myriad of opportunities in its current IRP and CEP processes to determine the least-risk, least-cost portfolio to continue serving customers. Given these uncertainties, PacifiCorp does not believe the Commission should act on AWEC's recommendations at this time.

**Q. Do you agree with AWEC's recommendation that the Commission revoke the Exit Orders for Naughton Units 1 and 2, since those units may remain in Oregon rates after 2030 following their conversion to natural gas?**

A. No. AWEC witness Kaufman is correct that Naughton Units 1 and 2 may remain in Oregon rates after PacifiCorp converts those units to natural gas generation. However, I do not agree that the Commission should revoke the existing Exit Orders for those units. Rather, I propose modifying the Exit Orders for Naughton Units 1 and 2 to clarify that the Exit Orders apply to those units only as coal-fired units. This approach

[125] AWEC/200, Kaufman/14.

is similar to the agreements parties reached in docket UE 399 related to the Jim Bridger gas conversion, which I described above.

**Q. Although Jim Bridger Units 3 and 4 are currently forecast to close in 2037, AWEC recommends an exit date for those facilities of December 31, 2028.[126] Do you agree that is an appropriate exit date for those units?**

A. No. AWEC recommends a 2028 exit date for those units because that is the same year carbon capture technology would be installed on those units. AWEC witness Kaufman opines that Oregon customers should not pay for these installations because the carbon capture technology "is designed to extend the lives of these units beyond when they can be included in Oregon rates." AWEC's recommendation to issue Exit Orders for Jim Bridger Units 3 and 4 is premature because PacifiCorp has not installed carbon capture technology on those units, nor does the Company seek cost recovery for any such technology in this case. AWEC's recommendation to address ratemaking treatment for a future investment is outside the scope of this GRC.

**Q. AWEC witness Kaufman also discusses a third-party decommissioning study (Kiewit Studies) that PacifiCorp prepared to estimate cost responsibility for exiting coal-fired plants prior to the plants' closure dates.[127] Are you familiar with those studies?**

A. Yes. As AWEC witness Kaufman discusses in his testimony, AWEC opposed using the Kiewit Studies for calculating decommissioning costs in docket UE 374.

[126] AWEC/200, Kaufman/2, 10-11.
[127] AWEC/200, Kaufman/7.

**Q. AWEC witness Kaufman suggests that an independent evaluator (IE) was unable to verify the Kiewit Studies and parties opposed use of the Kiewit Studies "because PacifiCorp refused to provide any of the underlying data Kiewit Studies relied on, stating that Kiewit was unwilling to release this information" and those same problems have continued in the Commission's subsequent decommissioning docket, UM 2183.[128] Do you agree with AWEC witness Kaufman's characterization of docket UM 2183?**

A. No, AWEC witness Kaufman's statements are inaccurate. First, it is notable that the decommissioning cost estimates from the Kiewit Studies are reflected in rates in all states *except* Oregon and have been for several years. While AWEC continues to complain about the Kiewit Studies, it is now proposing to rely on them for certain coal units, as addressed below.

Second, the Kiewit Studies were detailed and technical and largely included all external data Kiewit relied upon. PacifiCorp also provided parties with all data it furnished to Kiewit. PacifiCorp does not have access to Kiewit's proprietary information and could not produce information outside of its control, but ultimately none of this information was material to a review of the accuracy of the studies, as AWEC now appears to acknowledge in proposing to rely on these studies.

Third, while docket UM 2183 has faced delays, the suggestion that lack of disclosures from Kiewit is the primary cause of those delays is incorrect. When docket UM 2183 first began, non-Company parties to the 2020 Protocol, including Staff, CUB, and AWEC, recommended that AWEC should issue a Request for

[128] AWEC/200, Kaufman/8.

Proposal (RFP) for an IE. AWEC decided against this course, but failed to inform PacifiCorp. PacifiCorp then had to negotiate its own RFP, develop a modified protective order (MPO) for the highly confidential information at issue in the docket to which parties at the time agreed to, and then conduct the RFP. Through that process, PacifiCorp retained Sargent & Lundy LLC (S&L) as the IE. PacifiCorp then had to re-negotiate an agreed-upon MPO at the request of parties in docket UM 2183 and had to receive agreement from Kiewit on the MPO modifications. Since then, PacifiCorp has worked to ensure that S&L obtains as much information as possible from Kiewit.

**Q. AWEC witness Kaufman further testifies that he believed Section 4.3.1.2 of the 2020 Protocol required PacifiCorp to undertake an updated decommissioning study for certain units. Please respond.**

A. As AWEC witness Kaufman acknowledges in his testimony, the 2020 Protocol did not require that PacifiCorp complete an updated decommissioning study, but instead stated that PacifiCorp intended to do so at that time. Due to many circumstances, including Oregon parties' ongoing review of the original Kiewit Studies in docket UM 2183, the Company no longer intends to prepare these updated decommissioning studies.

**Q. AWEC witness Kaufman implies that PacifiCorp should have filed a new depreciation study in a timely manner.[129] Please respond.**

A. The relevant timing requirement for updated depreciation studies is in OAR 860-027-0350(2), which requires a utility to "file a new depreciation study with the

[129] AWEC/200, Kaufman/14.

Commission no less frequently than once every five years." While PacifiCorp filed its most recent depreciation study with the Commission in September 2018, the Commission did not approve that study until 2020.[130] Contemporaneously, four of five of PacifiCorp's sister-state utility commissions[131] approved the Company's same depreciation study, though subject to additional settlement conditions which directed the Company to file its next depreciation study within five years *of the respective commission order*, rather than from the date the last depreciation study was filed, resulting in a requirement to file the next study in 2025. However, the Commission's order on PacifiCorp's 2018 depreciation study did not include the same or similar requirement. To align with the requirements to file a deprecation study in each state jurisdiction in 2025, the Company requested a limited waiver of OAR 860-027-0350(2), which the Commission granted.[132]

**Q. AWEC now recommends that the Commission adopt the Kiewit Studies' estimates as Oregon's final decommissioning responsibility for Dave Johnson Unit 4 and Jim Bridger Units 3 and 4 and close docket UM 2183.[133] Would the Company agree with using the Kiewit Studies to estimate final decommissioning costs for those units?**

A. No. The Kiewit Studies remain the Company's best estimate of its future decommissioning costs and the Company intends to include these estimates in depreciation rates as a component of its 2025 depreciation study. However, the Kiewit

[130] *In re PacifiCorp's 2018 Depreciation Rates*, Docket No. UM 1968, Order No. 20-470, at 1 (Dec. 16, 2020).
[131] The 2018 Depreciation Study was filed with the California Public Utility Commission on May 5, 2022, as part of the Company's 2023 GRC, A.22-05-006.
[132] *In the Matter of PacifiCorp, dba Pac. Power, Petition for Limited Waiver of OAR 860-027-0350(2)*, Docket No. UM 1631, Order No. 24-074 (Mar. 21, 2024).
[133] AWEC/200, Kaufman/10.

Studies do not reflect inflationary pressures or the increasing risk that utilities operating in Oregon have faced in recent years. Given the passage of time, the Company no longer believes that the Kiewit Studies should be used to set final and binding decommissioning costs for Oregon as contemplated in the 2020 Protocol. For this reason, the Company agrees that it is appropriate to close docket UM 2183.

## VIII. DISTRIBUTION SYSTEM PLANNING DEFERRAL

**Q. PacifiCorp filed a motion to consolidate docket UM 2220 with this GRC.[134] What does the Company seek in docket UM 2220?**

A. In docket UM 2220 PacifiCorp initially sought deferral of the operating costs and capital investments made to implement and operate the Company's DSP for the 12-month period beginning on January 3, 2022.[135] In Order No. 22-260, the Commission adopted Staff's recommendation to defer those expenses. PacifiCorp moved to consolidate docket UM 2220 with this GRC to amortize these deferred expenses. PacifiCorp subsequently filed two supplemental applications seeking to continue deferring DSP expenses incurred in two subsequent 12-month periods. The Commission had not approved those supplemental applications at the time that PacifiCorp moved to consolidate docket UM 2220 with this docket.

**Q. What types of costs does the Company seek to recover through the docket UM 2220 deferral?**

A. PacifiCorp seeks recovery of non-capital expenses that the Company has incurred enacting its DSP. PacifiCorp intends to seek recovery of its capital investments made for DSP in a future rate case.

[134] PacifiCorp's Motion to Consolidate (Mar. 6, 2024).
[135] Docket No. UM 2220, Application for Deferred Accounting at 2.

**Q. What is the total cost of the deferred DSP expenses for which PacifiCorp seeks ratemaking treatment in this docket?**

A. The Company seeks ratemaking treatment for the DSP costs incurred in 2022 and 2023, which total $2.1 million.

**Q. If the Commission approves rate recovery for the $2.1 million in DSP expenses incurred in 2022 and 2023, will the Company continue seeking to defer DSP expenses incurred in subsequent years?**

A. Yes. The Company intends to continue tracking deferred costs through a deferral application until DSP costs can be reliably forecasted on an annual basis and included into base rates.

**Q. Has any party opposed ratemaking treatment for the deferred DSP expenses?**

A. Yes. Staff does not support recovery of PacifiCorp's deferred DSP expenses. Staff asserts that the deferred expenses are "driven by staffing costs and consulting costs," which Staff believes "are a normal part of regulatory lag that the Company should be expected to absorb."[136] Staff states that they do not oppose including these costs in future rates but believe that the costs incurred in 2022 and 2023 were "neither large enough in magnitude nor unexpected enough to qualify for a deferral." For these same reasons, Staff does not support continuing to defer most of the costs PacifiCorp has identified in docket UM 2220.

**Q. How do you respond to Staff's assertion that the costs the Company seeks to recover do not qualify for a deferral?**

A. Staff's position is contrary to the position Staff took in July 2022 when it

[136] Staff/700, Dlouhy/35.

recommended approving these costs for the deferral. Staff does not assert in its testimony that these costs were imprudent or unrelated to DSP. Rather, Staff has reversed its previous conclusion that these costs are eligible for deferral.

**Q. Do you agree that the costs PacifiCorp has sought to defer are normal expenses that the Company should be expected to absorb?**

A. No, I do not. PacifiCorp incurred these costs in direct response to a newly adopted Commission program requiring investments to achieve the Commission's DSP goals. The Commission has historically recognized that costs arising from new mandates placed on utilities can be deferred.[137] Consistent with that history, the costs that PacifiCorp has incurred and will continue to incur in developing and implementing the Company's DSP should be recoverable through the docket UM 2220 deferral.

**Q. Staff stated that it does not oppose including these costs in rates going forward. Why has the Company not sought to include DSP costs in its base rates?**

A. As stated above, PacifiCorp will seek to incorporate these expenses into rates once they can be reliably forecasted into a test year. However, currently the expenses incurred for DSP have not been steady and those expenses remain difficult to forecast.

## IX. UNDISCLOSED ADDITIONAL ADJUSTMENTS IN SUBSEQUENT TESTIMONIES

**Q. Do you have any general concerns regarding the opening testimony?**

A. Yes. I was taken aback by the number of times in testimony that Staff indicated that its investigation was on-going and reserved the right to make adjustments in rebuttal

[137] *See, e.g.*, *In the Matter of Pub. Util. Comm'n of Or. Staff Request to Open an Investigation Related to Deferred Accounting*, Docket No. UM 1147, Order No. 05-1070 at 2 (Oct. 5, 2005) ("The Commission has used deferrals for a variety of reasons, including to . . . implement legislative mandates or unique ratemaking mechanisms[.]").

testimony. I was similarly concerned by statements from CUB witnesses indicating that their positions may change and they may suggest "other possible solutions" after reviewing other parties' testimonies.[138] I understand the time constraints that a rate case can place on a party's resources—indeed, for its reply testimony, the Company was allotted just 28 days to conduct discovery, conduct settlement discussions, and prepare and file reply testimony responding to 33 pieces of opening testimony from nine intervenors. But Staff's and CUB's approach to opening testimony is problematic for several reasons.

First, without analyses or other calculations supporting temporary positions taken (as investigation is ongoing) or criticisms offered, the Company cannot effectively respond to these parties' testimony. As a result, the Company loses a round of testimony as it cannot properly respond to a position that does not currently exist or may be amended in rebuttal testimony.

Second, the parties' approach to opening testimony frustrates the purpose of the Commission's practice to allow multiple rounds of pre-filed testimony. Generally, with each round of testimony, issues between parties should be narrowing. This allows for the evidentiary hearings to be conducted in an efficient and effective manner, thus alleviating resource constraints for the Commission, the Company, and intervenors. However, in this proceeding, because some parties have deferred possibly substantial adjustments to rebuttal testimony, other parties are foreclosed from the opportunity to provide cross-answering testimony, and the Company may have to conduct extensive discovery and prepare and submit comprehensive

[138] CUB/100, Jenks/79; CUB/300, Garrett/11.

testimony in the very limited time (i.e., two weeks) allotted for surrebuttal testimony. The purpose of multiple rounds of testimony is to narrow issues and provide a full record on often complex ratemaking topics, not to allow some parties to expand the proceeding late in the process and prejudice other parties' opportunity to fully respond.

**Q. Do you have other concerns about Staff's process for identifying recommended adjustments in this case?**

A. Yes. Staff witness Laurel Anderson raises a concern regarding affiliated interests but states that Staff does not recommend an adjustment "at this time."[139] To the extent Staff witness Anderson intends to recommend an additional adjustment in future testimony, such a recommendation would be problematic for the reasons discussed above.

**Q. Did Staff identify a reason for delaying a potential recommendation?**

A. Staff witness Anderson explained that Staff issued DRs related to the Company's Affiliated Interest Charges, but PacifiCorp's "[r]esponses to these DRs were not returned sufficiently in advance of drafting this testimony for my analysis to be incorporated."[140]

**Q. How do you respond to Staff witness Anderson's concern?**

A. I believe Staff witness Anderson is referring to Staff DRs 590-92. To the extent Staff suggests that there was insufficient time to analyze concerns regarding affiliated interest charges, I believe it is important to consider the timeline of these DRs.

[139] Staff/500, Anderson/2.
[140] Staff/500, Anderson/2.

PacifiCorp filed its direct testimony on February 14, 2024. Over three months later, Staff issued DRs 590-92 on May 22, and PacifiCorp timely responded on June 5. Because PacifiCorp timely responded to Staff's DRs, any suggestion that the responses were not received in time to prepare reply testimony is a result of Staff's timing when issuing the DRs. Moreover, after PacifiCorp responded, Staff still had more than three weeks to review the Company's responses and incorporate any concerns into testimony that was due June 28.

For these reasons, Staff could have raised in its opening testimony adjustments relating to the Company's affiliated interest charges and PacifiCorp does not believe additional adjustments in future testimony would be proper.

## X. INTRODUCTION OF WITNESSES

**Q. Please identify the witnesses supporting PacifiCorp's reply position and the subject of their testimony.**

A. In addition to myself, the Company witnesses filing reply testimony and the subjects of their testimonies are as follows:

- In Exhibit PAC/2100, Nikki L. Kobliha, Senior Vice President, Chief Financial Officer & Treasurer, addresses the Company's overall cost of capital, capital structure, and updated cost of debt. Company witness Kobliha also addresses the reasonableness of the Company's pension and post-retirement medical benefit costs.

- In Exhibit PAC/2200, Ann E. Bulkley, Principal at The Brattle Group, provides updated analysis and supports the Company's cost of equity and capital structure.

- In Exhibit PAC/2300, Joelle R. Steward, Senior Vice President of Regulation, addresses the Company's wildfire insurance costs and proposed mechanisms.

- In Exhibit PAC/2400, Mariya V. Coleman, Vice President of Corporate Insurance and Claims for Berkshire Hathaway Energy Company, addresses the Company's wildfire insurance costs, both forecast and deferred.

- In Exhibit PAC/2500, Rick T. Link, Senior Vice President of Resource Planning, Procurement and Optimization, addresses the prudence of the Gateway South segments. Company witness Link also adopts Company witness Thomas Burns' testimony sponsoring the economic analysis of the Company's major capital projects, including the Gateway South segments and the Jim Bridger gas conversion.

- In Exhibit PAC/2600, Richard A. Vail, Vice President of Transmission Services, addresses the Gateway South segments, including the prudence of the planning and construction of the project and how its capacity will be fully utilized.

- In Exhibit PAC/2700, Timothy J. Hemstreet, Vice President of Renewable Energy Development, addresses cost recovery for the Fall Creek Hatchery, built in compliance with the Klamath Hydroelectric Settlement Agreement.

- In Exhibit PAC/2800, Brad D. Richards, Vice President of Thermal Generation, addresses the reasonableness of O&M expenses at Jim Bridger Units 1 and 2.

- In Exhibit PAC/2900, Allen Berreth, Vice President of Power Delivery Operations, addresses the reasonableness of the Company's wildfire mitigation costs, including the Juniper Ridge Bend Service Center.

- In Exhibit PAC/3000, James Owen, Vice President of Environmental & Energy Resources, updates fuel stock inventory balances at PacifiCorp's coal-fired plants and specifically addresses fuel stock balances at the Jim Bridger plant.

- In Exhibit PAC/3100, Ramon Mitchell, Director, Net Power Costs, addresses how Qualifying Facility generation should be modeled in NPC.

- In Exhibit PAC/3200, Kenneth Lee Elder, Jr., Manager of Load Forecasting, addresses changes proposed to the Company's load forecasting process.

- In Exhibit PAC/3300, Sherona L. Cheung, Revenue Requirement Manager, provides the updated Oregon Results of Operations for the Company's reply case and addresses various adjustments to the Company's revenue requirement.

- In Exhibit PAC/3400, Anna DeMers, Senior Customer Regulatory Specialist, addresses the Company's proposed Capacity Reservation Charge, Excess Demand Charge, and line extension policies.

- In Exhibit PAC/3500, Robert M. Meredith, Director of Pricing and Tariff Policy, provides the Company's updated pricing and rate spread, reflecting changes in the Company's reply case. Company witness Meredith also addresses the Low-Income Discount, disconnections and arrearages.

**Q. Does this conclude your reply testimony?**

A. Yes.

**REDACTED**
Docket No. UE 433
Exhibit PAC/2001
Witness: Matthew D. McVee

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**REDACTED**

**Exhibit Accompanying Reply Testimony of Matthew D. McVee**

**Moody's Downgrade of Sierra Pacific Power**

**July 2024**

# THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE 433
Exhibit PAC/2100
Witness: Nikki L. Kobliha

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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# Reply Testimony of Nikki L. Kobliha

**July 2024**

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## ATTACHED EXHIBIT

Confidential Exhibit PAC/2101—Proforma Cost of Long-Term Debt

**Q. Are you the same Nikki L. Kobliha who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?**

A. Yes, I am.

## I. PURPOSE AND SUMMARY OF TESTIMONY

**Q. What is the purpose of your reply testimony?**

A. I will respond to certain issues raised in the opening testimony filed by Lance D. Kaufman on behalf of the Alliance of Western Energy Consumers (AWEC), by Bob Jenks on behalf of the Oregon Citizen' Utility Board (CUB) and by Matt Muldoon on behalf of the Public Utility Commission of Oregon (Commission) Staff (Staff). I will also update the Company's proposed cost of capital.

**Q. Please explain how your testimony is organized and the issues you will address in your reply testimony.**

A. I will comment on the following issues and recommendations.

1. In Section II, I discuss my recommended cost of debt updates and address AWEC's recommendations for cost of debt.
2. In Section III, I respond to the recommendations by AWEC, on the Company's proposed capital structure and explain why the Company's proposed capital structure is reasonable and necessary. I also respond to comments made by CUB regarding Berkshire Hathaway Energy's (BHE) support and ownership of the Company.

3. In Section IV, I explain why Staff's recommendation to increase the Company's expected return on assets for the Company's pension and other post-retirement employee benefits (OPEB) plan should be rejected.

## II. COST OF DEBT

**Q. Are you recommending an update to the Company's cost of long-term debt?**

A. Yes. I recommend an updated cost of debt of 5.28 percent. Since the filing of this rate case in Oregon, the Company has revised its financing strategy to include junior subordinated notes.[1]

**Q. Please explain why the Company plans to use junior subordinated notes.**

A. PacifiCorp has completed the majority of its recent long-term financing using secured first mortgage bonds issued under the Mortgage Indenture dated January 9, 1989. PacifiCorp is forecasting the issuance of junior subordinated notes which have five- and 10-year-no-call features, can have an ultimate maturity of 30 to 60 years, and have interest rate reset features every five to 10 years with the interest rate being fixed between the reset periods. The Company currently anticipates issuing an additional $1.0 billion of debt in 2025 in the form of junior subordinated notes rather than first mortgage bonds largely due to credit metric pressures. Unlike first mortgage bonds, which are treated as 100 percent debt in the Company's funds from operations divided by debt ("FFO to debt") metric, junior subordinated notes are treated as 50 percent debt and 50 percent equity by both Standard & Poor's (S&P) and Moody's due to flexible interest payment features and call options. This treatment will support

[1] *In the matter of PacifiCorp dba Pacific Power, Application for authority to (1) Issue and Sell or Exchange not more than $5,000,000,000 of Debt, and (2) Enter Into a Credit Agreement,* Docket No. UF 4354, Motion to Amend Order No. 24-090 (June 26, 2024) (approved on consent agenda at July 23, 2024 OPUC Public Meeting).

the Company's efforts to maintain metrics that meet rating agency guidance and minimize the risk of further downgrade.

**Q. Regarding the $1.0 billion of new long-term issuances in 2025, how did you determine the interest rate and resulting cost for this new long-term debt?**

A. The Company's current estimated indicative rate for a 30-year no-call five-year junior subordinated note is 7.25 percent. Issuance costs for this debt adds approximately 0.10 percent to the all in cost. Therefore, as reflected in Confidential Exhibit PAC/2101 Pro Forma Cost of Long-Term Debt, the Company projects a total all-in cost of long-term debt of 7.35 percent, for the projected new long-term debt.

**Q. What overall cost of capital are you now recommending for PacifiCorp?**

A. I am recommending an overall cost of capital of 7.47 percent. This cost includes the return on equity (ROE) recommendation of 9.65 percent, supported by the reply testimony of Company witness Matthew D. McVee, and the capital structure and costs as shown in Table 1.

**Table 1: Overall Cost of Capital**

| Component | % of Total | Cost % | Weighted Ave Cost % |
|---|---|---|---|
| Long-Term Debt | 49.99% | 5.28% | 2.64% |
| Preferred Stock | 0.01% | 6.75% | 0.00% |
| Common Stock Equity | 50.00% | 9.65% | 4.83% |
| | 100.00% | | 7.47% |

**Q. AWEC suggests the Company's cost of debt should be reduced to reflect borrowing rates for the Company prior to the credit rating downgrades in 2023. Is that position reasonable?**

A. No. In June 2023 and November 2023 PacifiCorp's issuer credit ratings were

downgraded by S&P from A to BBB+[2] and by Moody's from A3 and Baa1. While the Company was disappointed with the credit downgrade, it is important to note the Company's ratings are still investment grade and in line with the majority of its utility peers and the utility industry average of BBB+. The Company has previously provided testimony in Oregon, and its other states, indicating a credit ratings downgrade could likely result in increased debt costs.[3] In prior testimony, the Company has argued for a capital structure in the 52 percent range which supported its rating of A and A3, noting the risk of having a capital structure that just supports the Company's rating, or is below ratings guidance, does not leave any room in the credit metrics for the Company to absorb unforeseen or significant disruptions in the Company's operating environment. Imputing the lower cost of debt is akin to saying PacifiCorp can only recover its actual debt costs if its ratings are A and A3 or higher from S&P and Moody's, respectively, which were the ratings prior to the end of 2023. As far as the Company is aware, no other peer utility has been held to such a standard. Penalizing the Company for incurring debt costs higher than the past is not justified particularly when the Company holds a rating similar to the majority of its peers.

[2] CUB witness Jenks states PacifiCorp was downgraded by S&P from AAA to BBB+ (see CUB/100, Jenks/41). This statement is not accurate as PacifiCorp's S&P rating was A prior to the downgrade.

[3] *See e.g., PacifiCorp dba Pacific Power, Request for a General Rate Revision,* Docket No. UE 399, PAC/200, Kobliha/2 ("Strong credit ratings provide for a more competitive cost of debt . . ."); *In the matter of PacifiCorp, dba Pacific Power, Request for General Rate Revision,* Docket No. UE 374 PAC/300, Kobliha/8 ("PacifiCorp's creditworthiness, as reflected in its credit ratings, will strongly influence its ability to attract capital in the competitive markets and the resulting cost of that capital.").

## III. CAPITAL STRUCTURE

**Q. AWEC suggests the Company's capital structure should reflect its actual ratio rather than the proposed hypothetical capital structure. What was AWEC's capital structure proposal?**

A. AWEC's capital structure proposes 44.35 common equity, 0.01 percent preferred stock and 44.99 percent for debt. This proposal does not add up to 100 percent, which is an incomplete accounting of the Company's financing sources. If the Commission agrees with AWEC's proposed common equity of 44.35 percent and 0.01 percent preferred stock, then the percentage for debt needs to be adjusted to 55.64 percent and included in any weighted average cost of capital calculation.

**Q. AWEC suggests a hypothetical capital structure should only be used in cases where the Company's actual capital structure is higher than the hypothetical capital structure. Is there any evidence supporting this position?**

A. AWEC provides no citation to support this position.[4] I disagree that a hypothetical capital structure is only appropriate in cases where a company's actual capital structure is higher than the hypothetical level. I cited several cases in my direct testimony where a hypothetical capital structure was approved when a company's actual capital structure was impaired, or lower than the hypothetical request.

**Q. AWEC testifies that the Company will have no incentive to move to an authorized hypothetical capital structure that is higher than its actual capital structure. What is your response?**

A. I disagree that the Company has no incentive to move to a hypothetical capital

[4] AWEC/200, Kaufman/50-51.

structure that is higher than its actual capital structure. As presented in Table 2 of my direct testimony the Company presented six years of history where the equity component of its capital structure was in excess of the 50 percent hypothetical request. The Company maintained this position as the level of equity necessary to support its strong credit ratings. Thinner actual equity that results in a higher ROE will not in isolation support the credit metrics the Company needs to maintain or improve its credit rating. In order to maintain or improve its credit metrics the Company needs to reduce its relative debt load, which is one of the reasons BHE has suspended dividends through 2028. To the extent the Company has earnings, does not pay a dividend and can limit the amount of debt it issues, its equity percentage will grow. It has not been until recently that the Company has not been able to maintain its historical equity level. The Company expects over time that the capital structure will be aligned with its historical levels.

**Q. AWEC claims the use of the proposed hypothetical capital structure will result in a "windfall profit to shareholders" of $15 million per year. Do you agree with this position?**

A. No. It is unclear from the statement and table that follows in AWEC's testimony how the $15 million windfall is calculated. Regardless, shareholders will not receive a windfall of profits from use of the hypothetical capital structure due to BHE's commitment to suspend any dividends from PacifiCorp at least through 2028. This means all earnings (profits) will remain at PacifiCorp to strengthen its financial position or invest in its significant capital expenditure program. As provided in my direct testimony, the Company is seeking a hypothetical capital structure at this time

in an effort to maintain its financial position and mitigate the risk of a future credit ratings downgrade.

**Q. AWEC indicates there are less costly ways to support improved credit metrics. Can you please explain actions the Company has taken to maintain its credit metrics through improved cash flow?**

A. AWEC provides suggestions as to how the Company can improve its cashflow, many of which have been pursued by the Company in the past.

First, the Company regularly seeks recovery of deferred costs, net power costs being among the larger deferrals. The Company follows procedural timelines prescribed by its various states, but this still results in the Company funding prudently incurred net power costs for in excess of 18 months in some cases, which negatively impacts credit metrics. As of December 31, 2023, the Company had $268.5 million in regulatory assets for net power costs that the Company financed and is waiting for collection from customers under the Oregon Power Cost Adjustment Mechanism (PCAM); $39.2 million for the 2021 Oregon PCAM, $109.5 million for the 2022 Oregon PCAM and $119.8 million for the 2023 Oregon PCAM. The $268.5 million does not contemplate the $121.0 million in net power costs that the Company is unable to collect from customers as a result of the dead band and sharing bands in the mechanism over the same period. Incurring significant costs and waiting two to three years for recovery is a meaningful strain on the Company's credit metrics.

Second, regarding depreciation, the Company cannot unilaterally update depreciation rates, it must file a depreciation study in order to update depreciation rates. The Company typically files a depreciation study every five years as required in

its various states.[5] The workload and cost to file a depreciation study and get agreement among all interested parties is significant which is why the Company has adhered to standard utility practice.

Third, in its 2020 general rate case, the Company proposed recovery of incremental increases in decommissioning costs but the Commission ordered that the decommissioning costs be reviewed in a separate proceeding,[6] which has experienced delays and may expose the Company to additional risk as explained by Company witness McVee.[7]

Finally, the Company has pursued the use of power purchase agreements as an alternative to owning resources as a way to lessen the amount of debt the Company must issue. However, it is important to remember power purchase agreements can result in a debt imputation by rating agencies and reduce credit metrics.

In addition to these options, the Company is also pursuing the issuance of junior subordinated notes as a cost-effective way to support credit metrics, as noted in the cost of debt section above. All strategies that are reasonably likely to be achieved are reflected in the Company's credit metric forecast and are needed in addition to the proposed hypothetical capital structure in order to maintain the metrics disclosed on Confidential Table 5 of my direct testimony.

In regard to the issuance of stock raised by AWEC, the Company is a wholly-owned subsidiary of BHE. As a result, its common stock is entirely held by BHE and

[5] *In the matter of PacifiCorp, dba Pacific Power, Petition for Limited Waiver of OAR 860-027-0350(2),* Docket No. UM 1631, Order No. 24-074 (Mar. 21, 2024) (order granting limited waiver of OAR 860-021-0350 allowing PacifiCorp to file its next depreciation study no later than December 31, 2025).
[6] *In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 17-19 (Dec. 18, 2020).
[7] *In the Matter of PacifiCorp dba Pacific Power, Application for Authority to Implement a Decommissioning Cost Recovery Adjustment and Coal Removal Mechanism,* Docket No. UM 2183, Application filed Jul. 8, 2021.

does not trade on an exchange. The tool to raise money from stock would be in the form of an equity contribution from BHE. Suspension of any dividends from PacifiCorp is exactly like an equity contribution, strengthening credit metrics.

**Q. AWEC testifies that the Company's equity ratio reduced from 53.3 percent to 50.06 percent from 2022 to 2023 due to an abnormally large $300 million dividend and further reduces to 44.19 percent in 2024 due to wildfire liabilities. Is this accurate?**

A. No. First and foremost, AWEC has not provided any evidence to support the dividend being abnormally large. Looking back over the last 10 years (2013 to 2023) dividends have averaged $439 million with each year fluctuating depending on net income for the year, authorized capital structures approved in rates and planned capital expenditures. The largest dividend during that time period was $950 million in 2015 and the smallest was zero in 2020. The $300 million dividend is not abnormally large when considering this history.

Next, the reduction in the Company's equity ratio from 2022 to 2023 is primarily driven by a combination of the $300 million dividend and the wildfire accrual recorded in 2023. Had the dividend not been declared the equity ratio would have been approximately 51 percent. Had the dividend not been declared and had the wildfire liability not been accrued the equity would have been approximately 53 percent. The forecast decline in 2024 is the combination of both these items coupled with the $3.8 billion of debt the Company issued to fund its significant capital program, which includes new renewables, the associated transmission, and wildfire mitigation capital.

**Q. AWEC suggests the Commission exclude the impacts of the wildfire liabilities from the capital structure. Can you explain what that means and how it compares to the hypothetical capital structure?**

A. If the Company were to exclude the wildfire liabilities recorded through December 2023, net of insurance and income taxes, the Company's five-quarter average capital structure for 2023 would have been approximately 52 percent instead of the 50 percent presented in Table 2 of my direct testimony. Absent any other changes, continuing to roll this adjustment forward through 2024 and 2025 would result in a forecast equity component of the capital structure at approximately 47 percent. However, it is difficult to predict how much debt the Company would have issued in January 2024 to fund its capital expenditures if it did not have the outstanding wildfire liability and associated risk. Hypothetically, reducing the debt issuance in January 2024 by half ($1.9 billion) would have resulted in a five-quarter common equity percentage of approximately 50 percent at the end of 2024 and 2025. Therefore, I believe our use of a hypothetical capital structure essentially excludes the impact of the wildfire liabilities and is reasonable at this time as the Company works its way through its current financial challenges.

**Q. CUB has concluded "BHE has pulled the plug" on its support of PacifiCorp and that Warren Buffett's statements show a lack of support, which puts downward pressure on credit ratings.[8] Do you agree with this characterization?**

A. Absolutely not. As discussed in my direct testimony, PacifiCorp is continuing to receive support from BHE through the suspension of dividends. Compared to other

[8] CUB/100, Jenks/42.

investor-owned utilities who dividend approximately 60 to 70 percent of their earnings to shareholders, PacifiCorp has no dividend requirement and has the further commitment for suspension of any dividend that could otherwise been paid through 2028. An investor who is "pulling the plug" would seek to extract every last bit of cash and equity it could, which is not the case here.

In terms of pressure on credit ratings, S&P uses a group rating methodology which rates PacifiCorp as part of the BHE family of companies. This methodology continues to provide a three-notch uplift to PacifiCorp's stand-alone credit profile. PacifiCorp is independently rated by Moody's but they do note the lack of dividend requirement is an advantage for the Company.

**Q. Can you expand on the role of BHE and Berkshire Hathaway Inc. (BHI) with the Company?**

A. The role of BHE and BHI is primarily that of an investor. Their role is no different than that of any investor in any investor-owned utility, or any publicly traded company for that matter. An investor may be an institutional or retail investor purchasing the stock of an investor-owned utility or investing in an index fund that includes investor-owned utilities and are no different than BHE or BHI. Investors, whether they are BHI, institutional or retail (including individuals with a 401(k)) are looking for a return on their investment. The fact that Mr. Buffett is wealthy and might have 'deep pockets' is not relevant to this proceeding. As stated in Mr. Buffett's 2023 annual letter to shareholders he "will not *knowingly* throw good money after bad" (emphasis added), which is advice that has surely influenced his wealth and is a foundation for any investor decision.

Mr. Buffett's ownership of PacifiCorp has been beneficial to the Company when it comes to not requiring PacifiCorp (through BHE) to pay a dividend. These benefits have been passed on to customers through the impact strong credit ratings have had on the Company's cost of debt and the ability to retain earnings to fund the significant capital expenditures over the years to build renewables and associated transmission needed for system reliability, which are also critical to support Oregon's clean energy goals.

**Q. CUB references testimony citing the benefits of BHE ownership during the acquisition of PacifiCorp in 2006 in the form of lower cost of debt.[9] Has PacifiCorp realized such benefits?**

A. Absolutely. If CUB were to refer back to testimony in prior Oregon rate cases he will find in the last two Company proceedings I have provided testimony on this exact issue going as far as providing an estimate of such benefits attributable to higher credit ratings.[10] It is unrealistic to think back in 2006 that witnesses in the acquisition proceeding could predict that wildfire risk and associated Oregon jury verdicts would drive a credit ratings downgrade. Despite the downgrade, PacifiCorp is still an investment grade utility with credit ratings in line with the industry average, and continues to reap the benefits of BHE ownership through a three-notch uplift compared to its stand-alone credit profile determined by S&P. But regulatory support in the form of approval of the hypothetical capital structure and approval of other

[9] CUB/100, Jenks/42.
[10] *PacifiCorp dba Pacific Power, Request for a General Rate Revision,* Docket No. UE 399, PAC/200, Kobliha/16-17; *In the matter of PacifiCorp, dba Pacific Power, Request for General Rate Revision,* Docket No. UE 374, PAC/300, Kobliha/11.

requests in the proceeding in response to the wildfire risks in the West and cost recovery, is still necessary to remain at this level.

## IV. PENSION AND POST-RETIREMENT MEDICAL BENEFITS

**Q. Staff challenges the expected return on plan assets assumptions utilized for the Company's defined benefit pension and other post-retirement plans, indicating the Company is shifting risk and cost to Oregon customers.[11] Staff performed their own analyses of the expected return on assets for the Company's plans and recommends revised net periodic benefit cost for the plans as a result. Do you agree with these recommended adjustments and the basis for the adjustments?**

A. No, I do not. Staff's adjustments are based on expected return on assets assumptions utilized by other utilities despite those assumptions being specific to their plans. While there is some discretion in selecting the expected return on assets assumptions for the Company's defined benefit plans, the assumptions are determined in accordance with generally accepted accounting principles and are based on plan-specific details, including investment mix and investment strategy of plan-specific assets, plan-specific benefit obligations, plan-specific duration and the associated funded status of the specific plans. It is inappropriate to consider assumptions of other plans when determining those to be used for the Company's plans.

**Q. How do you respond to Staff's concern that the Company's derisking means that more risk and cost is shifted to Oregon customers?**

A. I disagree with Staff's concern and believe the Company has actually reduced the risk of costs shifting to customers. The Company closely monitors the funded status of its

[11] Staff/100, Muldoon/50.

plans and has slowly begun to de-risk its investment portfolio over time in anticipation of future funding requirements, to mitigate the risk of stranded assets and associated tax consequences I described above, and to reduce exposure to market risk as the plans have become better funded. By shifting away from heavily investing in return-seeking investments and investing more in fixed-income securities, in the event of a market downturn, the plans would be less likely to revert to being underfunded, mitigating the risk that additional contributions to the plans will be required. Furthermore, the blended return of the fixed-income and equities securities provide for an expected return on assets that exceeds the discount rate such that in combination with the funded status of the plans provides for the expected return on assets component of expense to exceed the interest cost.

**Q. Please provide a more detailed explanation as to why do you disagree with Staff's analysis and recommendations related to the expected return on plan assets assumptions for the Company's plans.**

A. Staff's analysis and resulting recommended adjustment to decrease the Company's net periodic benefit cost is based on the averaging of expected return on assets assumptions of several other utilities. Such an approach is flawed as it is both unreasonable to rely on assumptions from others' plans and is unacceptable under Accounting Standards Codification Topics 715-30, Defined Benefit Plans-Pension (ASC 715-30) and 715-60, Defined Benefit Plans-Other Postretirement (ASC 715-60).

**Q. Why is it unreasonable to consider assumptions from other entities' defined benefit plans in determining net periodic benefit cost for the Company's plans?**

A. Each defined benefit plan differs in the types of benefits provided, participant population and demographics, plan experience, timing of benefit payments, investment mix and strategy, unrecognized actuarial gains and losses, prior service costs, etc. The determination of expected return on plan assets and other assumptions is influenced by factors specific to a defined benefit plan and, therefore, are not only appropriate to be determined on a plan-specific basis but are required to be under generally accepted accounting principles.

**Q. Why is it unacceptable under ASC 715-30 and 715-60 to consider other entities' assumptions in determining the Company's net periodic benefit cost for its pension and OPEB plans?**

A. Both ASC 715-30 and ASC 715-60 require the use of explicit assumptions individually representing the best estimate of future activity associated with the plans' specific obligations. With respect to the expected return on assets assumption, ASC 715-30-35-47 states:

> The expected long-term rate of return on plan assets shall reflect the average rate of earnings expected on the funds invested or to be invested to provide for the benefits included in the projected benefit obligation. In estimating that rate, appropriate consideration shall be given to the returns being earned by the plan assets in the fund and the rates of return expected to be available for reinvestment. The expected long-term rate of return on plan assets is used (with the market-related value of assets) to compute the expected return on assets. In the context of its use in this paragraph, funds to be invested refers only to the reinvestment of returns on existing plan assets.

ASC 715-60-35-84 similarly states:

> The expected long-term rate of return on plan assets shall reflect the average rate of earnings expected on the existing assets that qualify

> as plan assets and contributions to the plan expected to be made during the period. In estimating that rate, appropriate consideration shall be given to the returns being earned on the plan assets currently invested and the rates of return expected to be available for reinvestment.

As a result, it is not acceptable under ASC 715-30 or 715-60 to rely on or utilize other entities' expected return on assets as the basis for the Company's asset return assumptions. Each plan's investment portfolio differs, for example, in investment mix, which is influenced by investment strategies that may change over time depending on a plan's funded status.

**Q. How do you respond to Staff's statement that the Company seeks to reduce the volatility and uncertainty of its expected return on assets more so than other utilities within the Commission's jurisdiction?[12]**

A. As indicated above, it is unreasonable to compare the Company's assumptions to those of other entities' plans that do not have the same investment mix, investment strategies, funded status, etc. The Company's expected return on assets assumption is specifically influenced by the plans' funded status, investment strategies and investment mix. Due to the favorable funded status of the plans,[13] the investment portfolio has been de-risked over time resulting in a lower allocation to equities and return-seeking assets, which results in lower returns on plan assets. The path toward de-risking has been in place for several years as the funded status of the plans improved and helps mitigate having excess plan assets at the end of the plans which

[12] Staff/100, Muldoon/49.
[13] As of December 31, 2023, PacifiCorp's pension plan was $65.0 million, or 109.3 percent, funded and the other post-retirement benefit plan was $55.4 million, or 125.7 percent, funded.

would be stranded or otherwise subject to significant income taxes if reverted to the Company (50 percent for pension plans and 100 percent for OPEB plans).

It is inappropriate to expect plan asset investment strategies and associated expected return on assets assumptions to be similar to other utilities that have their own specific benefit obligations, plan assets and funded status.

**Q. What is your recommendation regarding the Company's net periodic benefit cost for its pension and OPEB plans?**

A. For the reasons set forth above, I recommend Staff's adjustment be rejected and that no changes be made to the net periodic benefit cost originally included in the case by the Company.

**Q. Does this conclude your reply testimony?**

A. Yes.

**REDACTED**
Docket No. UE 433
Exhibit PAC/2101
Witness: Nikki L. Kobliha

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**REDACTED**

**Exhibit Accompanying Reply Testimony of Nikki L. Kobliha**

**Proforma Cost of Long-Term Debt**

**July 2024**

# THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE 433
Exhibit PAC/2200
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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# Reply Testimony of Ann E. Bulkley

**July 2024**

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**ATTACHED EXHIBITS**

Exhibit PAC/2201—Summary of Updated Cost of Equity Results

Exhibit PAC/2202—Constant Growth Discounted Cash Flow Model

Exhibit PAC/2203—Multi-Stage Discounted Cash Flow Model

Exhibit PAC/2204—Gross Domestic Product Growth

Exhibit PAC/2205—Capital Asset Pricing Model and Empirical Capital Asset Pricing Model

Exhibit PAC/2206—Long-Term Beta Coefficient

Exhibit PAC/2207—Market Return

Exhibit PAC/2208—Risk Premium Approach

Exhibit PAC/2209—Business Segment Data

Exhibit PAC/2210—Revised Staff Constant Growth DCF Analysis

Exhibit PAC/2211—Revision to Staff Hamada Adjustment

Exhibit PAC/2212—Revised Staff Multi-Stage DCF Analysis (Model X)

Exhibit PAC/2213—Revised Staff Multi-Stage DCF Analysis (Model Y)

Exhibit PAC/2214—Adjustment to Staff Model Results Summary

Exhibit PAC/2215—Market Value Capital Structures- Staff and Bulkley Proxy Group

Exhibit PAC/2216—Revised Staff CAPM Analysis

Exhibit PAC/2217—Summary of the Effect of AWEC's Methodological Changes

Exhibit PAC/2218—Summary of Adjustments to AWEC Multi-Stage DCF

Exhibit PAC/2219—AWEC's Constant Growth DCF using their Prior Testimony Assumptions

Exhibit PAC/2220—AWEC's CAPM and ECAPM Using Prior Testimony Assumptions

Exhibit PAC/2221—Hamada Adjustment with AWEC's Proposed Capital Structure

Exhibit PAC/2222—OPUC Response to PacifiCorp Data Request 8

## I. PURPOSE AND SUMMARY OF TESTIMONY

**Q. Are you the same Ann E. Bulkley who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?**

A. Yes.

**Q. What is the purpose of your reply testimony?**

A. The purpose of my reply testimony is to respond to the opening testimony of Matt Muldoon on behalf of the Staff of the Public Utility Commission of Oregon (Commission) (Staff), Lance D. Kaufman on behalf of the Alliance of Western Energy Consumers (AWEC), Eric S. Austin on behalf of Walmart, Inc. (Walmart), and Bob Jenks on behalf of the Oregon Citizens' Utility Board (CUB), as it relates to the just and reasonable return on equity (ROE) and the appropriate capital structure for PacifiCorp in Oregon.

**Q. Are you sponsoring any exhibits as part of your reply testimony?**

A. Yes, I am sponsoring Exhibits PAC/2201 through PAC/2222, which have been prepared by me or under my direct supervision.

**Q. How is the remainder of your reply testimony organized?**

A. The remainder of my reply testimony is organized as follows:

- Section II provides a summary and overview of my reply testimony and the important factors to be considered in establishing the authorized ROE for PacifiCorp.
- Section III discusses the changes in capital market conditions since my direct testimony was filed and responds to the other ROE witnesses' testimony regarding the effect of economic and capital market conditions on the cost of equity and the implications for the financial models used to estimate the authorized ROE in this proceeding.

- Section IV provides the update to my cost of equity analyses based on market data as of June 30, 2024.
- Section V provides my response to Staff's ROE and capital structure analyses and recommendations.
- Section VI provides my response to AWEC's ROE and capital structure analyses and recommendations.
- Section VII responds to Walmart's testimony regarding the cost of equity.
- Section VIII responds to CUB's testimony regarding the cost of equity.

## II. SUMMARY AND OVERVIEW

**Q. What factors should be considered in evaluating the results of ROE models and establishing the authorized ROE?**

A. The primary factors that should be considered are: (i) the importance of investors' actual return requirements and the critical role of judgment in selecting the appropriate ROE; (ii) the importance of providing a return that is comparable to returns on alternative investments with commensurate risk; (iii) the need for a return that supports a utility's ability to attract needed capital at reasonable terms; and (iv) the effect of current and expected capital market conditions.

**Q. What is the Company's current proposed ROE in this proceeding?**

A. As discussed in the reply testimony of Company witness Matthew D. McVee, the Company has revised its proposed ROE from 10.30 percent to 9.65 percent to mitigate the rate increase and address concerns about affordability.

**Q. What are the ROE recommendations of the other witnesses in this proceeding?**

A. Figure 1 below summarizes the results of the ROE analyses presented by the other witnesses in this proceeding and their final recommendations. While AWEC

recommends an authorized ROE for PacifiCorp of 9.25 percent,[1] Staff does not propose a point estimate. Staff simply concludes that the results of their analyses indicate a range of reasonableness of 9.09 to 9.55 percent.[2] The following are important considerations when reviewing the range of results and recommendations in Figure 1:

**Figure 1: Summary of Staff and AWEC Model Results**[3]

| | Staff | AWEC Mean/Median |
|---|---|---|
| Constant Growth Discounted Cash Flow (DCF) | | |
| Projected Dividend Growth Rate [4] | 8.40% | N/A |
| Projected Earnings Growth | | N/A |
| Sustainable Growth | | 8.59%-9.64% |
| Multi-Stage DCF | 9.09%-9.55%[5] | 8.63%-9.91% |
| Capital Asset Pricing Model (CAPM) | 8.70%[6] | 7.94%-9.88% |
| Empirical Capital Asset Pricing Model (ECAPM) | | 8.33%-10.30% |
| Risk Premium | | N/A |
| ROE Recommendation | 9.09%-9.55%[7] | 9.25% |

Walmart did not conduct any cost of equity models or any analysis that compares PacifiCorp to a proxy group of risk comparable companies. Walmart's

[1] AWEC/200, Kaufman/3.
[2] Staff/100, Muldoon/21.
[3] Walmart witness Austin did not perform his own ROE recommendation and therefore is not included in this summary table.
[4] Staff/100, Muldoon/44. Staff does not rely on the results of the Constant Growth DCF model, but rather uses this as a check on the Multi-Stage DCF results.
[5] *Id.,* at 25.
[6] *Id.,* at 27. Staff does not rely on the results of the CAPM, but rather uses this as a check on the Multi-Stage DCF results.
[7] *Id.,* at 25.

testimony simply states, without any analysis to support their positions, that the Company's requested ROE is excessive due to the customer impacts of the overall revenue requirement, the ratemaking structures, and previously authorized ROEs by this Commission in different market conditions, without consideration of whether or not the ROEs were the result of settlements or litigation.

**Q. What are your key conclusions and recommendations regarding the appropriate ROE and capital structure for PacifiCorp?**

A. Nothing in the testimonies of Staff or AWEC has caused me to change my conclusions and recommendations. Based on my review of their respective testimonies, my key conclusions regarding a reasonable ROE and capital structure for the Company in this proceeding are as follows:

***1. Current market conditions and recent authorized ROEs demonstrate that the cost of equity has increased since the Company's last case.***

- Updating the cost of equity estimation models that I relied upon in my direct testimony to reflect the most current data demonstrates that the cost of equity has increased since the filing of my direct testimony, and the model results continue to support the Company's initial proposed ROE in this proceeding of 10.30 percent and demonstrate that the Company's revised proposed ROE of 9.65 percent is conservative, particularly when considering the Company's overall business risks as discussed in my direct testimony.

- As discussed in detail herein, while I disagree with various elements of the cost of equity analyses of Staff and AWEC, as well as their respective comments regarding my cost of equity analyses, the most significant flaw is that their ROE recommendations are inconsistent with the changes in capital market conditions since the Company's last rate proceeding in 2022.

- The following changes in market conditions since the Company's last rate proceeding in 2022 support an increase in the cost of equity:

  a. The federal funds rate has increased approximately 301 basis points since the last evidence that was introduced in the Company's last rate proceeding.

b. The yield on the 30-year Treasury bond has increased approximately 135 basis points.

c. While core inflation has declined since the Company's last rate proceeding, it remains significantly above the Federal Reserve Open Market Committee's target level of 2.00 percent.

- Despite the undeniable significant increase in the cost of equity demonstrated by current market conditions, AWEC suggest the Company's cost of equity should ***decrease by 25 basis*** points to 9.25 percent. Staff suggests a range that could be a ***reduction of 50 basis points to an increase of 5 basis points*** as compared with the Company's currently authorized ROE.

  a. While there is some speculation about potential changes in interest rates in the future, current macroeconomic data continues to demonstrate strength in the economy, which has resulted in the Federal Reserve Open Market Committee (FOMC) maintaining interest rates at these higher levels.

  b. Further, even if interest rates decline, there is no indication that the FOMC has intentions of returning interest rates to the levels that existed when the Company's last rate case was determined, meaning it is reasonable to expect that the cost of equity for the Company is currently higher and will remain higher in the near future than its currently authorized ROE.

- Authorized ROEs for vertically integrated utilities have also increased since the Company's last rate proceeding. The current average authorized ROE for vertically integrated utilities is higher than the Company's revised proposed ROE of 9.65 percent, demonstrating that the proposal is conservative, particularly when considering the significant business risks discussed in my direct testimony.[8]

- Based on this data, the ROE recommendations of Staff and AWEC cannot be reconciled with the differences in market conditions since the Company's last rate proceeding.

***2. Methodological changes have had the effect of suppressing the cost of equity estimates from the Staff and AWEC models.***

- Staff witness Muldoon and AWEC witness Kaufman have both changed the methodologies that they have relied upon with the effect being that the results of those models have decreased, when compared to recent previous testimony supported by these witnesses.

- Staff witness Muldoon made three changes to the gross domestic product (GDP) growth rates relied on in the third stage of Staff's Multi-Stage DCF model in the current proceeding from the GDP growth rates Staff witness

[8] *See* Walmart/102 Austin/2.

Muldoon relied on in Company's last rate proceeding, docket UE 399: 1) adjusted the weighting on the historical and projected GDP growth rates used to calculate composite GDP growth ; 2) a Multi-Stage DCF scenario using the Bureau of Economic Analysis (BEA) historical GDP growth rate in the current proceeding was not developed where as in the Company's last rate proceeding, Staff witness Muldoon relied on solely on this scenario to develop Staff's recommended ROE range; and 3) a Multi-Stage DCF scenario was not developed using my GDP growth rate in the current proceeding.

a. Since the historical and projected GDP growth rate have generally increased since docket UE 399, it appears that each of the three changes Staff witness Muldoon has made resulted in a decrease in the results of Staff's Multi-Stage DCF model as compared with Staff witness Muldoon's prior testimony.

b. If Staff witness Muldoon had relied on the Multi-Stage DCF model using the BEA historical GDP growth rate as in docket UE 399, Staff's recommended ROE range would increase from 9.09 percent to 9.55 (midpoint of 9.32 percent) percent to 9.18 percent to 9.94 percent (midpoint of 9.56 percent).

- AWEC witness Kaufman understates the cost of equity by ***adjusting the assumptions relied upon in every model*** that was developed for this proceeding when compared to other testimonies AWEC witness Kaufman has filed within the last year:

a. Constant Growth DCF Model: Reverting back to the use of Value Line EPS growth rates in the constant growth DCF model, consistent with the assumptions used in AWEC witness Kaufman's testimony in September 2023, results in a cost of equity range of 9.78 to 10.13 percent, which are 79 to 105 basis points higher than the results of the constant growth DCF results proposed in the current proceeding.[9]

b. Multi-Stage DCF Model: Reverting back to the use of the 30-year Treasury bond yield as the long-term growth rate, which is consistent with AWEC witness Kaufman's analysis in May 2024 results in an increase in AWEC's multi-stage DCF model results of 45 to 47 basis points, and a cost of equity range of 9.62 to 9.94 percent.[10]

c. CAPM: Relying on a market risk premium that is calculated consistent with the approach used in AWEC witness Kaufman's testimony in

[9] *See* PAC/2219.
[10] *Id*.

September 2023 results in an upper bound on the cost of equity of 10.62 to 10.59 percent, an increase of 74 basis points.[11]

***3. When reasonable adjustments are made to Staff's cost of equity analyses, the results of their Constant Growth DCF, Multi-Stage DCF and CAPM analyses support the Company's initial proposed ROE of 10.30 percent and demonstrate that the Company's revised proposed ROE of 9.65 percent is conservative.***

- Multi-Stage DCF: Correcting Staff witness Muldoon's Hamada adjustment and relying on the Multi-Stage DCF results using the BEA historical nominal GDP growth rate to develop Staff's recommended ROE range similar to the approach Staff witness Muldoon relied on in the Company's last rate proceeding, would increase Staff's recommended ROE range to 10.00 percent to 10.52 percent with a midpoint of 10.26 percent.

- Constant Growth DCF: Removing negative dividend growth rates and also relying on projected earnings growth rates results in an increase in Staff's Constant Growth DCF result from 8.40 percent to 9.64 percent. If the flotation cost adjustment and corrected Hamada adjustment are applied similar to Staff's Multi-Stage DCF model, the resulting ROE produced by the adjusted Constant Growth DCF analysis would be 10.22 percent.

- CAPM: Relying on the geometric average return for the Standard & Poor's 500 Index (S&P 500) over the 30-year period of 1994 through 2023 of 10.31 percent as reported by *Kroll* instead of Staff's calculation of the 30-year geometric return for the S&P 500, for which no workpaper support was provided, increases Staff's CAPM result from 8.67 percent to 9.79 percent.

***4. Updates to my cost of equity models and the models developed by AWEC to rely on data through June 30, 2024, demonstrates that the Company's revised proposed ROE of 9.65 percent is conservative.***

- Updates to AWEC witness Kaufman's analyses using the methodologies that AWEC witness Kaufman has relied on in recent testimonies and market data through June 30, 2024, increase AWEC's constant growth DCF results to a range of 9.89 percent to 10.58 percent.

- Updates to AWEC witness Kaufman's multi-stage DCF to rely on the methodologies that AWEC witness Kaufman used in prior testimony and market data through June 30, 2024, result in a cost of equity range of 9.30 percent to 10.55 percent.

- As shown in PAC/2201, updating my DCF results through June 30, 2023 demonstrates that the Company's revised proposed ROE is at the low end of

[11] *Id.*

the range of average DCF results using the Constant Growth DCF model and is below the low end of the multi-stage DCF model results and the results of the other risk premium approaches, demonstrating that the Company's revised proposed ROE is conservative, particularly when considering the Company's overall risk profile, as discussed in my direct testimony.

***5. The Company's proposed Capital Structure is reasonable and consistent with the proxy group equity ratios.***

- The Company's hypothetical capital structure, which includes 50.00 percent equity, is consistent with the actual capital structures of the utility operating companies owned by the proxy group companies as shown in Exhibit PAC/416 and is therefore, reasonable.

***6. Relying on the Company's projected capital structure will result in increased financial risk that should be reflected in the cost of equity.***

- AWEC's recommendation to authorize the Company's projected equity ratio of 44.35 percent substantially increases the financial risk of the Company relative to the proxy group as the projected equity ratio is 854 basis points below the average equity ratio of the proxy group companies of 52.89 percent as shown in Exhibit PAC/416. However, AWEC has not considered the additional financial risk when developing their ROE recommendation. As shown in Exhibit PAC/2221, if AWEC had applied the Hamada adjustment similar to Staff to account for the difference in financial risk as a result of their proposed equity ratio, AWEC's ROE recommendation would have increased 100 basis points from 9.25 percent to 10.25 percent.

**7. *CUB's proposal to make an arbitrary adjustment to the return on equity to address policy objectives is inconsistent with the fair return standards established in Hope and Bluefield and the Commission's historical precent and therefore should be rejected.***

## III. CAPITAL MARKET CONDITIONS

**Q. Do changes in capital market conditions since the Company's last rate proceeding continue to indicate an increase in the cost of equity?**

A. Yes. Changes in long-term bond yields since the Company's 2022 rate proceeding demonstrate an increase in the cost of capital. Specifically, as shown in Figure 2, the federal funds rate has increased approximately 300 basis points since the testimony was filed and 100 basis points since the final order in the Company's last rate

proceeding. Treasury bond yields have increased 72 to 135 basis points when comparing to these same time periods. While core inflation rate has declined since that time, it remains well above the Federal Reserve's target level of two percent. This demonstrates that the cost of equity for PacifiCorp is significantly higher today than at the time of the Company's last rate proceeding.

**Figure 2: Change in Market Conditions Since PacifiCorp's Last Rate Proceeding**

| Period | Date | Federal Funds Rate | 30-Day Avg of 30-Year Treasury Bond Yield | Core Inflation Rate | Auth'd ROE |
|---|---|---|---|---|---|
| Surrebutal - UE-399 | 7/31/2022 | 2.32% | 3.15% | 5.89% | |
| Decision - UE-399 | 12/16/2022 | 4.33% | 3.78% | 5.70% | 9.50% |
| | | | | | |
| Direct Testimony | 11/30/2023 | 5.33% | 4.76% | 4.03% | |
| Rebuttal Testimony | 6/30/2024 | 5.33% | 4.50% | 3.28% | |
| | | | | | |
| Change since UE-399 Testimony | | | | | |
| Current - Surrebuttal | | 3.01% | 1.35% | -2.61% | |
| Current - Decision | | 1.00% | 0.72% | -2.43% | |

**Q. Do the ROE recommendations of the Staff and AWEC appropriately reflect the change in market conditions since the Company's 2022 rate proceeding?**

A. No. Despite the *higher* cost of equity demonstrated by current market conditions, Staff recommends an ROE range of 9.09 percent to 9.55 percent, which suggests a 40 basis point reduction to a 5 basis point increase in the cost of equity. Staff does not provide a point estimate. AWEC recommends a decrease in the ROE of 25 basis points, despite the higher overall market cost of equity.

The recommendations of these witnesses clearly do not fully reflect the effect of the changes in market conditions since the Company's last rate proceeding when it was authorized a 9.50 percent ROE.

**Q. What is your response to Staff regarding the expectations for interest rates and what they represent as "the downward glide path of utility ROEs".[12]**

A. First, it is important to note that Staff's analysis has been truncated to 2021, which does not reflect the increase in interest rates since that time period. Further, Staff's argument is premised on the assumption that utility ROEs are positively correlated with interest rates, which, is inconsistent with Staff's recommended range, which largely suggests a decrease in the cost of equity, to at most an increase of 5 basis points. While I generally agree with the relationship that Staff has established, it is important to recognize, as shown in Figure 2 of my reply testimony, that interest rates have increased since the Company's last rate proceeding. Therefore, it would be reasonable to expect that the Company's ROE would also increase.

**Q. What are the expectations for inflation and monetary policy over the near-term?**

A. Over the last several months the FOMC has been clear that it intends to rely on market data before making any changes to interest rates. In the FOMC's meeting on June 12, 2024, Chairman Powell observed that the FOMC will make its decision "meeting by meeting."[13] Further, while the FOMC forecasts one 25 basis point rate cut in 2024,[14] Chairman Powell noted that is just a projection and not a "plan," and indicated that the FOMC is prepared to maintain the current federal funds rate range higher for longer if needed to reduce inflation.[15]

Similarly, Boston Federal Reserve President Susan Collins (Collins) recently commented that she thought the federal funds rate would need to be kept at its current

[12] Staff/100 Muldoon/39-40.
[13] Federal Reserve, Transcript of Chair Powell's Press Conference at 4 (June 12, 2024).
[14] Federal Reserve, Summary of Economic Projections at 2 (June 12, 2024).
[15] Federal Reserve, Transcript of Chair Powell's Press Conference at 4 (June 12, 2024).

level until there was greater confidence that inflation was moving sustainably towards 2 percent.[16] Collins cited improvements in supply chains as the reason inflation declined in 2023, but that may not continue in 2024 and that slower economic growth will be needed to reduce demand in order to further reduce inflation.[17] New York Federal Reserve President John Williams and Minneapolis Federal Reserve President Neel Kashkari also recently stated that the federal funds rate will need to remain at its current level for longer as more data is collected.[18] More recently, Minneapolis Federal Reserve President Neel Kashkari added that he wanted to see "[m]any more months of positive inflation data" before there is a rate cut and that he has not ruled out further rate increases if inflation does not continue to decrease.[19]

**Q. What are investors' expectations for the yields on long-term government bonds given the sustained elevated levels of inflation and the Federal Reserve's restrictive monetary policy?**

A. Investors expect long-term interest rates to remain elevated. The most recent *Blue Chip Financial Forecasts* report indicates that the consensus estimate of the average yield on the 30-year Treasury bond is 4.32 percent through 4Q/2025 and is also 4.30 percent over the longer term through 2030, meaning long-term interest rates are expected to remain elevated during the period that the Company's rates will be in effect.[20]

[16] Steve Matthews, Fed's Collins Says Reaching 2% Inflation Goal May Take Longer, Bloomberg (May 8, 2024).
[17] Jennifer Schonberger, Collins Becomes Latest Fed Official to Warn Rates Will Likely Stay Higher for Longer, Yahoo! Finance (May 8, 2024).
[18] *Id*.
[19] Karen Gilchrist, Fed's Kashkari wants to see 'many more months' of positive inflation data before a rate cut, CNBC (May 28, 2024).
[20] *Blue Chip Financial Forecasts*, Vol. 43, No. 7, July 1, 2024, at 2 and Vol. 43, No. 6, May 31, 2024, at 14.

**Q. What are equity analysts' current projections regarding the performance of the utilities sector over the near-term?**

A. Various equity analysts continue to project that utilities will underperform the broader market given the substantial increases in interest rates over the past two years:

- Fidelity Investments continues to classify the utility sector as underweight.[21]
- CFRA Research recently classified the utility sector as underweight, stating that the 10-year Treasury yield, which CFRA noted is the "benchmark for gauging the attractiveness of utility valuations and yields," exceeded the dividend yield of the utilities included in the S&P Composite 1500.[22]
- UBS classified the 11 sectors of the S&P 500 for 2024 as either most preferred, neutral, or least preferred with the utility sector being classified as one of UBS's three least preferred sectors (*i.e.*, utilities, materials and real estate).[23]
- Professional investors surveyed by *Barron's* in its most recent Big Money poll published in May 2024 selected the utility sector as one of the five equity sectors that they liked the least over the next 12 months, indicating they are projecting that utilities will underperform the broader market over the next 12 months.[24]

**Q. What are your conclusions regarding the effect of current market conditions on the Company's cost of equity in this proceeding?**

A. Current interest rates are higher than at the time of the Company's last rate proceeding. The Federal Funds rate is 100 to 300 basis points higher whereas the yield on the 30-year Treasury bond is approximately 72 to 135 basis points higher than at the time the Company filed its last rate proceeding. While there is speculation as to the timing of any interest rate reductions from the FOMC, their recent actions demonstrate that any decision to reduce interest rates will be measured. Therefore, it is reasonable to expect that in the short-term, interest rates will likely remain elevated

[21] Fidelity Investments, *Second Quarter 2024 Investment Research Update*, at 3 (Apr. 22, 2024).
[22] Daniel Rich, U.S. Utilities – Cherry-picking Quality in an Underperforming Sector, CFRA (Jan. 26, 2024).
[23] Jason Capul, UBS Prefers Info Tech, Consumer Staples and Energy in 2024, Seeking Alpha (Dec. 12, 2023).
[24] Paul La Monica, The Stock Market Will Rise Nearly 10% More This Year, Money Managers Predict in Barron's Latest Poll, Barron's (May 3, 2024).

at levels that exceed those at the time of the Company's last rate proceeding, demonstrating that the current cost of equity is higher than at that time.

## IV. UPDATED COST OF EQUITY ANALYSES

**Q. Have you updated your cost of equity analyses?**

A. Yes. I have updated the results of the cost of equity analyses conducted in my direct testimony based on market data through June 30, 2024, using the same methodologies as in my direct testimony.

**Q. Have you relied on the same proxy group for your updated analyses as you relied upon in your direct testimony?**

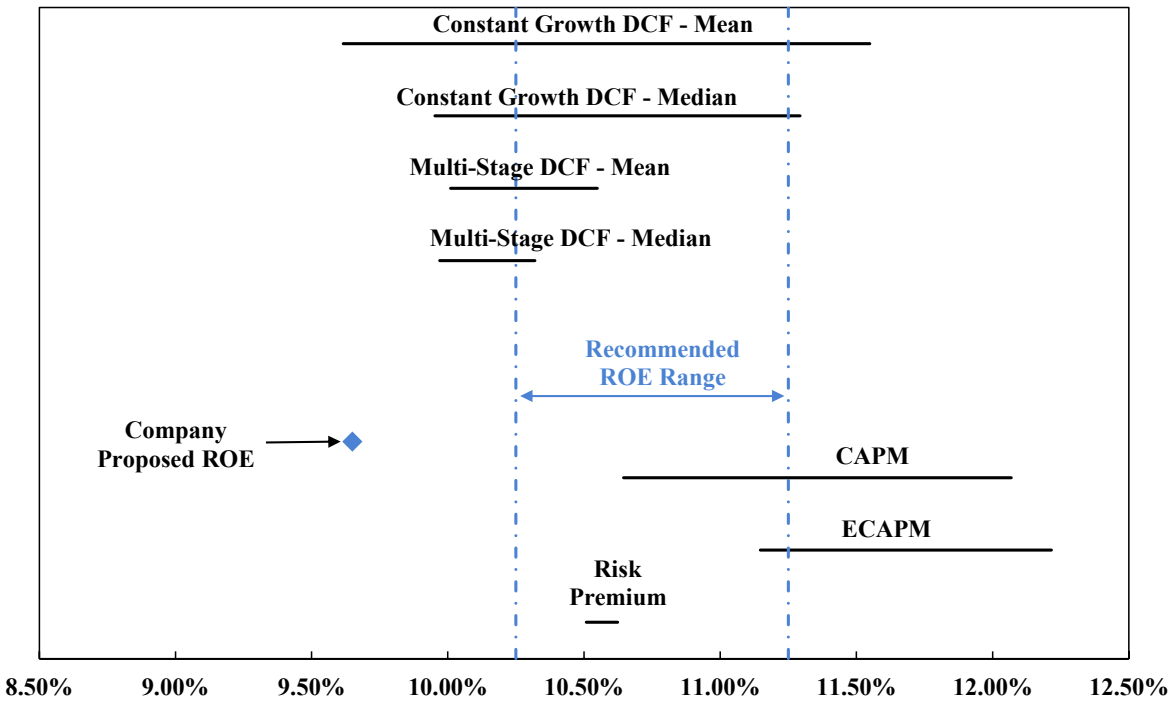
A. Yes, with the exception of ALLETE, Inc., which was acquired after I filed my direct testimony and thus would not pass the merger and acquisition screening criterion discussed in my direct testimony. In addition, I have updated my analyses to include all of the United States (U.S.) jurisdictional companies included in Staff's analyses.

**Q. What are the updated results of your cost of equity analyses?**

A. Figure 3 summarizes the results of my updated analyses as of June 30, 2024, using my proxy group, which are also presented in Exhibits PAC/2201 to PAC/2208. As shown, the updated results of the cost of equity analyses continue to support the Company's original requested ROE of 10.30 percent and also demonstrate that the Company's revised requested ROE of 9.65 percent is well below the estimated range of the investor-required return, using all of the traditional cost of equity models and therefore is conservative. Specifically, the results of DCF, CAPM and ECAPM analyses have increased as compared to the results presented in my direct testimony.

Further, the results of the Risk Premium analysis are generally consistent with the results presented in my direct testimony.

**Figure 3: Summary of Updated Cost of Equity Results**




## V. RESPONSE TO STAFF WITNESS STAFF

**Q. Please summarize Staff's ROE analyses and recommendation.**

A. Staff develops a range of results of 9.09 percent to 9.55 percent, based on the results of their Multi-Stage DCF model.[25] While Staff does not recommended an ROE for PacifiCorp which is a deviation from past practice, they do note that the midpoint of their range is 9.30 percent and utilizes 9.30 percent when estimating Staff's proposed weighted average cost of capital shown in Table 6 of their opening testimony. Staff's recommended ROE range of 9.09 percent to 9.55 percent is based solely on the results of the Multi-Stage DCF model. Staff also considers a Constant Growth DCF

[25] Staff/100, Muldoon/21.

analysis and a CAPM analysis to test the reasonableness of their Multi-Stage DCF results but does not give those other models any weight in establishing the recommended ROE range for PacifiCorp.[26] Further, Staff does not oppose the Company's proposed capital structure comprised of 50.00 percent common equity, 49.99 percent long-term debt and 0.01 percent preferred equity.[27]

**Q. What are your principal areas of disagreement with Staff's analyses and recommendation?**

A. Staff and I disagree on the following aspects of the ROE estimation models and considerations in developing a recommended ROE: (1) the composition of the proxy group; (2) the application of the Multi-Stage DCF model, particularly the long-term growth rate assumption and the inputs to the Hamada equation; (3) the importance of considering the results of multiple models, including the Constant Growth DCF, CAPM, and Risk Premium analyses to check the reasonableness of the DCF results and to inform the ultimate ROE recommendation; and (4) other factors that support a cost of equity above the proxy group mean, including elevated capital spending levels and above average business risks relative to the proxy group.

**A. Proxy Group Composition**

**Q. Do you have any concerns with the screening criteria Staff has used to select their proxy group?**

A. Yes, I do. As shown in Figure 4 below, Staff's screening criteria results in the exclusion of seven companies that would be considered comparable to PacifiCorp. As

[26] *Id*., at 21-22.
[27] *Id.,* at 17-18.

a result, there are three primary areas where I disagree with the screening criteria that Staff has applied to the companies classified by *Value Line* as Electric Utilities:

1. The regulated electric revenue screen, which, as shown in Figure 4, one company included in my proxy group did not pass. Moreover, as I will discuss in more detail below, Staff's misapplication of the regulated electric revenue screen results in the inclusion of three companies (Black Hills Corporation (BKH), Sempra Energy (SRE), and WEC Energy Group, Inc. (WEC)) in their proxy group that should have been excluded.

2. The capital structure screen that requires a company have a long-term debt ratio as calculated by *Value Line* between 45 percent and 55 percent, which, as shown in, seven companies included in my proxy group did not pass.

3. The requirement that a company not be involved in any merger or acquisition activity, which, as shown in, one company included in my proxy group did not pass.

**Figure 4: Bulkley Proxy Group Companies Eliminated Due to Staff's Screening Criteria[28]**

| Company | Regulated Electric Revenue | Debt Ratio | M&A Activity |
|---|---|---|---|
| American Electric Power Company, Inc. | Pass | Fail | Pass |
| CMS Energy Corporation | Pass | Fail | Pass |
| Duke Energy Corporation | Pass | Fail | Pass |
| Entergy Corporation | Pass | Fail | Fail |
| NextEra Energy, Inc. | Fail | Fail | Pass |
| Southern Company | Pass | Fail | Pass |
| Xcel Energy Inc. | Pass | Fail | Pass |

[28] Source: Staff/102 Muldoon/2. It is important to note that as shown in Staff/102 Muldoon/2, Staff witness Muldoon contends that both Staff and the Company have included PPL Corporation (PPL) in our respective proxy groups. However, I did not include PPL in my proxy group because the Company had a dividend cut in the last three years. Further, since Staff requires companies not have a dividend cut in the last five years, PPL should also be excluded from Staff's proxy group.

**1. Regulated Electric Revenue Screening Criterion**

**Q. Do you agree with Staff's application of a revenue screen to identify proxy companies that are primarily engaged in electric utility operations like PacifiCorp is in Oregon?**

A. No, I do not. Staff has selected companies for their proxy group that have "heavily regulated electric utility revenue". While this is not quantified in the testimony, in Exhibit Staff/102, it appears that Staff is applying a regulated revenue screen that excludes companies with less than 80 percent of revenues from regulated operations. I have three main concerns with Staff's "heavily regulated electric utility revenue" screen. First, the way that Staff applies this screen does not accomplish what they suggest, establishing a proxy group with significant **regulated electric** revenue. Staff's screening criterion, as applied, only ensures that the companies included in their proxy group have 80 percent or greater revenues from **regulated operations.** Therefore, this screen does not ensure that the companies are primarily regulated electric utilities.

Second, Staff does not appear to apply the "heavily regulated electric utility revenue" screen consistently. For example, as noted above, Staff's screen requires companies included in their proxy group have 80 percent or greater revenues from **regulated operations**. However, Staff included Fortis, Inc. (Fortis) in their proxy group, even though, as shown in Exhibit Staff/102, Fortis derived only 55 percent of its revenue from regulated operations. It is evident that Fortis did not meet Staff's application of the "heavily regulated electric utility revenue" screen and should have been excluded from their proxy group.

Third, I disagree with the use of revenue as the screening criterion. The use of revenue can skew the results of this screen based on changes in fuel costs and other operating costs. It is more appropriate to rely on net operating income because net operating income is more representative of the contribution of that business segment to earnings.

**Q. Does Staff's misapplication of theirs regulated electric revenue screen result in the inclusion of companies that do not have "heavily regulated electric utility revenue"?**

A. Yes, it does. As noted above, Staff contends they have relied on a screening criterion that ensures the companies included in their proxy group derive a substantial portion of total revenues from regulated electric operations. However, Staff's screen only determines if a company derives 80 percent of its total revenue from regulated operations. Staff does not determine the percentage of revenue derived from regulated electric operations. This results in the inclusion of companies that derive a significant portion of revenue from other regulated operations such as natural gas. For example, BKH was included in Staff's proxy group; however, as shown in Exhibit PAC/2209, BKH derived only 38.57 percent of its total revenue from regulated electric operations for the three-year period of 2020-2022. BKH has significant regulated natural gas operations and therefore, from 2020-2022, BKH derived 56.38 percent of its total revenue from regulated natural gas operations. Similarly, SRE and WEC were also included in Staff's proxy group; however, as shown in Exhibit PAC/2209, SRE and WEC derived only 51.38 percent and 55.13 percent, respectively, of total revenue from regulated electric operations for the three-year period of 2020-2022. It is clear

that had Staff relied on a screen that ensured companies had "heavily regulated electric utility revenue" similar to PacifiCorp that BKH, SRE and WEC would not have been included in their proxy group.

**Q. Please explain why regulated operating income is a more appropriate screen than regulated revenues.**

A. Net operating income is more representative of the contribution of that business segment to earnings and the corporation's overall financial position than total revenue. Specifically, a significant portion of electric utility company revenue is derived from the costs of purchased fuel and purchased power, which, in most cases, are recoverable through tracking mechanisms and do not, therefore, contribute to earnings. Furthermore, this portion of total revenue can fluctuate considerably based on the cost of fuel and purchased power. Therefore, relying exclusively on a revenue screen does not provide a clear or necessarily consistent indication of the contribution of the regulated utility operations to a company's earnings. Net operating income excludes the cost of purchased commodity and therefore more closely represents the contribution of the business segment to a company's earnings.

**2. Long-term Debt Ratio Screening Criterion**

**Q. Please describe the screen Staff has applied based on the capital structure of the potential proxy group company.**

A. Staff includes companies in the proxy group if their capital structure has between 45 and 55 percent long-term debt according to *Value Line*. Staff provides no support for why this range is appropriate for PacifiCorp.

**Q. Is this screen reasonable?**

A. No. I have three concerns with Staff's capital structure screen:

1. Staff's use of a credit rating screen and a capital structure screen is unnecessary in that the financial risk that it apparently is being used to assess is addressed in another screen. Therefore, this criterion merely serves to reduce the size of the group without providing any benefit of making the group more comparable to PacifiCorp. As discussed previously, the development of the proxy group necessarily balances the size of the group with comparability. The use of a credit rating screen achieves this balance without overly restricting the sample size.

2. The use of a long-term debt ratio screen is even less relevant considering that Staff, ultimately, adjusts their Multi-Stage DCF results using the Hamada equation. While I do not agree with Staff's specific adjustment since they relied on the book value of debt and equity, and address this separately in my reply testimony, the Hamada equation specifically accounts for differences in financial risk as a result of capital structure between the subject and proxy group companies. Therefore, the additional use of a long-term debt ratio screen is unnecessary and overly restricts the proxy group.

3. As noted above and discussed in more detail below in regard to Staff's use of the Hamada equation, if Staff was going to consider the capital structures at the holding company level as a capital structure screen, the market value of debt and equity must be used to estimate the percentage of debt and equity in the capital structure, not the book value of debt and equity such as Staff has done. This is because while Staff's proxy group screen is based on the book value of debt and equity, the cost of equity is being determined using the market value of equity not the book value. For example, Staff considers the Multi-Stage DCF model to determine the cost of equity for the Company, which they estimate using the current stock prices of the proxy group companies (i.e., the current market value of their equity). Therefore, by relying on the book value of debt and equity to screen their proxy group, Staff has created a mismatch between the data that is being used to estimate the cost of equity and the data that is being used to screen their proxy group. If the market value of debt and equity deviate substantially from the book value of debt and equity, Staff's capital structure screen will not provide an accurate assessment of the financial risk of the companies that they are considering for inclusion in their proxy group.

**Q. Is the book value debt ratio different from the market value debt ratio for Staff's proxy group?**

A. Yes. As shown in Exhibit PAC/2215**,** the average market value debt ratio for Staff's proxy group as of December 31, 2023, was 43.86 percent which is well below the

average book value debt ratio for their proxy group of 51.3 percent. Given the substantial difference between the market and book value of debt, it is eident that Staff's capital structure screen does not accurately assess the financial risk of the companies they considered for inclusion in their proxy group and therefore, could unreasonably exclude companies that investors would deem comparable to PacifiCorp.

**Q. Are there companies that are unnecessarily eliminated from the proxy group based on Staff's capitalization ratio screen?**

A. Yes. As shown in Figure 5 below, there are seven companies that were included in my proxy group that did not meet Staff's long-term debt ratio screen. Of those seven companies, five companies (American Electric Power Company, Inc., CMS Energy Corporation, Duke Energy Corporation, Southern Company, and Xcel Energy Inc.) met each of the remaining screens applied by Staff and thus were only excluded due to their long-term debt ratio screen.

**Figure 5: Proxy Companies Excluded by Staff based on the Capitalization Ratio Screen**

| Company |
|---|
| American Electric Power Company, Inc. |
| CMS Energy Corporation |
| Duke Energy Corporation |
| Entergy Corporation |
| NextEra Energy, Inc. |
| Southern Company |
| Xcel Energy Inc. |

**3. Mergers & Acquisitions (M&A) Screening Criterion**

**Q. Please explain the purpose of a M&A screening criterion.**

A. The purpose of applying an M&A screen is to isolate companies that are involved in transformative transactions, that is transactions that will cause a fundamental change in a company and its financials. The larger the size of the transaction, the greater likelihood the transaction will have a significant effect on the share prices of the firms involved. Thus, it is important to exclude the companies from the proxy group that are involved in transformative transactions so that the temporary effect of the transaction does not affect the ROE model results. Excluding companies based on either smaller, non-transformative transactions or transactions that occurred well before the analytical period being relied on to estimate the ROE unnecessarily reduces the size of the proxy group and eliminates companies that investors would consider comparable.

**Q. Is Staff's M&A screening criterion consistent with the objectives you described?**

A. No, it is not. My primary concern with Staff's M&A screen is that their application of the M&A screen resulted in Entergy Corporation (ETR) not meeting their M&A screen even though ETR was not engaged in a transaction that would be considered transformative. Transactions that are smaller in size are less likely to affect the market data of the company.

**Q. Have you reviewed the transaction for ETR that Staff determined to be transformative?**

A. Yes, I did. Figure 6 provides the detail behind the transaction that Staff deemed transformative for ETR. ETR has agreed to sell its natural gas distribution business in

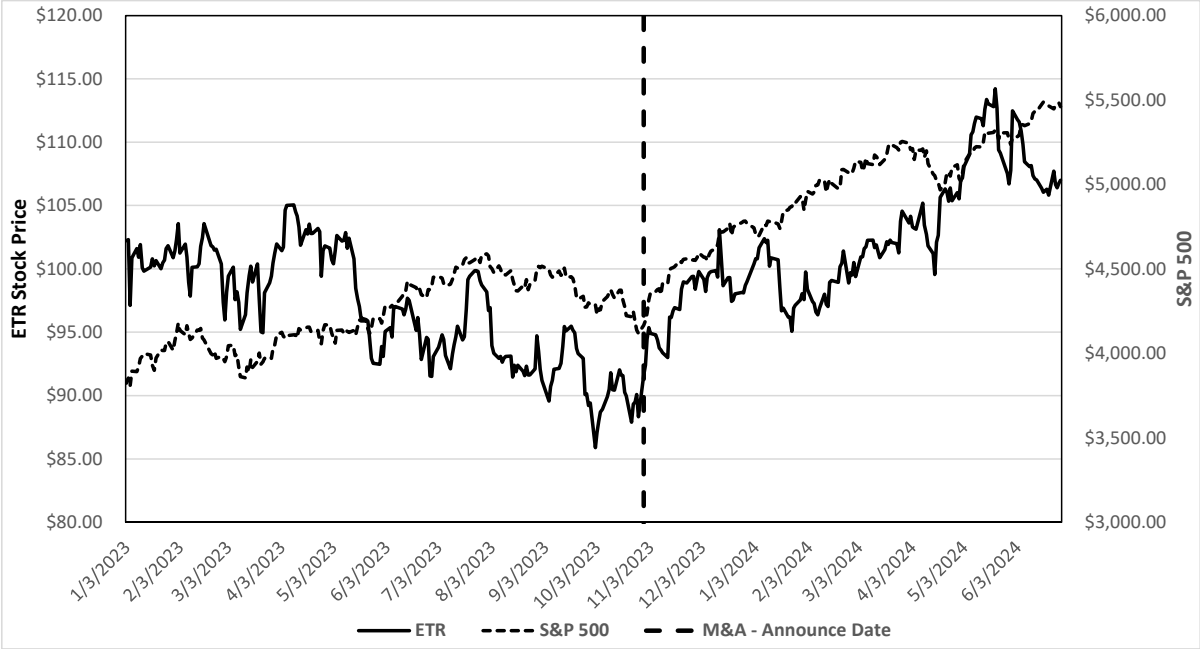
Louisiana to Bernhard Capital Partners Management for $484 million. As shown in Exhibit Staff/102, Staff appears to incorrectly report the sale price as $1.2 billion as opposed to $484 million which may have led them to conclude that the transaction was transformative. However, if the correct sale price of $484 million is used, it is clear that the transaction is too small to be considered transformative. For example, as shown in Figure 6, ETR has total net utility plant as of 2023 of $43.82 billion which means this transaction represented only 1.10 percent of 2023 net plant. Further, in an article detailing the transaction, S&P noted that "[t]his is a somewhat small transaction relative to Entergy's market cap of more than $20 billion."[29] Finally, Figure 7 is an event study that compares the stock price of ETR to the S&P 500 Index prior to and following the announcement of the transaction. As shown in this study, the stock price of ETR was not unduly influenced by the announcement of the sale of its natural gas distribution business in Louisiana. Therefore, it is reasonable to continue to include ETR in the proxy group.[30]

**Figure 6: Staff – Review of ETR M&A Transaction[31]**

| Company | Ticker | Acquisition/Sale | | | | 2023 Total Net Plant ($Billions) | Price / Net Plant |
|---|---|---|---|---|---|---|---|
| | | Description | Price ($Millions) | Announced Date | Close Date | | |
| Entergy Corporation | ETR | Sale of Gas Distribution Business in Louisiana | $484 | 10/30/2023 | N/A | $43.82 | 1.10% |

[29] Jim Davis, *Entergy agrees to sell La. gas utility business to Bernhard Capital*, S&P Capital IQ Pro (Nov. 1, 2023).
[30] While ETR should not be excluded on the basis of M&A activity, the company does not meet Staff's debt ratio screen and would still be excluded from their proxy group. However, as I discussed above, I disagree with Staff's use of a debt ratio screen as he has relied on the book value of debt and equity as opposed to the market value of debt and equity.
[31] S&P Capital IQ Pro.

**Figure 7: ETR Stock Price**




**4. Generation Ownership Screening Criterion**

**Q. Do you have any other concerns with the screening criteria relied on by Staff to develop their proxy group for PacifiCorp?**

A. Yes, I do. Staff has not applied a screen to remove companies that do not own substantial amounts of generation and therefore, may not be as comparable to the Company.

**Q. Please explain your generation ownership screens.**

A. I have selected companies that own regulated generation assets because they have a different risk profile than companies that do not own generation (i.e., transmission and distribution (T&D) only utilities). Furthermore, in order to increase the risk comparability to PacifiCorp in Oregon, I have applied an additional screen based on the percentage of sales derived from owned generation facilities. Staff, on the other hand, has not applied a generation screen, and has therefore included companies that

own very limited regulated generation. In particular, Staff's proxy group includes Consolidated Edison, Inc. and Public Service Enterprise Group Inc., both of which own very limited regulated generation assets and therefore are not risk comparable to PacifiCorp.

**Q. What evidence is there that investors consider companies that own generation facilities to have higher risk than T&D utilities?**

A. The generation function is generally regarded by investors as being higher risk than electric transmission or distribution. As stated by Moody's in its ratings methodology for regulated electric and gas utilities:

> Generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays. [32]

**5. Inclusion of Fortis, Inc.**

**Q. What is your concern with Staff's inclusion of Fortis in their proxy group?**

A. First, as noted above, it is unclear why Staff included Fortis in their proxy group since Fortis did not meet Staff's application of the "heavily regulated electric utility revenue" screen. Second, while I recognize that Fortis owns companies that are regulated in the U.S., there is also a significant portion of this company's operations that are under Canadian regulations, which are not comparable to U.S. regulation. For

[32] *Rating Methodology: Regulated Electric and Gas Utilities*, Moody's Investors Service, at 21 (Jun. 23, 2017).

example, as shown in Exhibit PAC/2209, over the period of 2020-2022, only 60 percent of Fortis's operating income was derived from U.S. operations. Further, as shown in in Exhibit Staff/105, and Figure 8 below, the beta estimate for Fortis is significantly below the average of the proxy group companies, which demonstrates that it is not comparable to the rest of the group.

**Figure 8: Staff Proxy Group Betas**

| Company | Value Line Betas |
|---|---|
| Alliant Energy Corporation | 0.90 |
| Ameren Corporation | 0.90 |
| Avista Corporation | 0.90 |
| Black Hills Corporation | 1.00 |
| Consolidated Edison, Inc. | 0.75 |
| Evergy, Inc. | 0.95 |
| Fortis, Inc. | 0.70 |
| IDACORP, Inc. | 0.85 |
| NorthWestern Corporation | 0.95 |
| OGE Energy Corporation | 1.05 |
| Portland General Electric Company | 0.90 |
| Pinnacle West Capital Corporation | 0.95 |
| PPL Corporation | 1.05 |
| Public Service Enterprise Group Inc. | 0.90 |
| Sempra Energy | 1.00 |
| Wisconsin Energy Corporation | 0.85 |
| **Mean** | **0.91** |

### 6. Conclusion

**Q. What is your conclusion regarding Staff's proxy group in this proceeding?**

A. While I believe it was Staff's intention to identify risk-comparable companies using their criteria, based on the following five reasons, I conclude that the proxy group developed by Staff is not comparable to PacifiCorp:

1. Staff's "heavily regulated electric utility revenue" screen is: 1) not applied to achieve a proxy group based on electric utility revenue and includes companies that have significant natural gas operations; and 2) not applied consistently since as shown in Exhibit Staff/102, Fortis does not meet Staff's "heavily regulated electric utility revenue" screen but is included in their proxy group.

2. Staff's long-term debt ratio screen is not appropriate because: 1) they have applied a credit rating screen which also considers financial risk; 2) they apply the Hamada adjustment to their DCF results to account for any difference in financial risk between PacifiCorp and the proxy group; and 3) they incorrectly rely on the book value of debt and equity to develop their screen as opposed to the market value of debt and equity which would be consistent with the inputs relied on to estimate their DCF and CAPM analyses.

3. Staff's M&A screen inappropriately excludes companies such as ETR which had smaller transactions that would not be considered transformative.

4. Staff fails to consider a key risk factor that has been identified by investors and credit rating agencies, generation ownership. This results in the inclusion of two companies that own minimal generation and therefore are not comparable to PacifiCorp, a vertically integrated utility.

5. Staff incorrectly includes PPL in their proxy group even though PPL does not meet their screen that requires companies not have a dividend cut in the last five years.

**Q. What proxy group does AWEC rely on to determine their recommended ROE for PacifiCorp?**

A. AWEC relies on the same proxy group as I have in my direct testimony to develop their recommended ROE for the Company.[33]

**Q. What can you conclude from AWEC's reliance on your proxy group?**

A. It is reasonable to conclude that AWEC did not disagree substantially with the screening criteria relied upon to establish the group. Further, it is reasonable to conclude that AWEC agrees that this proxy group is reasonably risk-comparable to PacifiCorp.

[33] AWEC/200, Kaufman/56.

**B. Multi-Stage DCF Analysis**

**1. Short-Term and Long-Term Growth Rate Assumptions**

**Q. Please summarize the differences in the assumptions relied on in your application of the Multi-Stage DCF model and the model developed by Staff.**

A. The Multi-Stage DCF models that Staff and I have relied on are generally similar in structure; we both use a three-stage model that relies on near-term growth in the first five-year period, transitional growth rates for the second stage (years six–10), and a long-term growth rate in year 11 and beyond. The primary difference in our analyses is the appropriate near-term and long-term growth rate used in the first and third stages of the model. Staff uses dividend and earnings growth rates from *Value Line* in the first stage, while I have used earnings growth rates from *Value Line*, Yahoo! Finance and Zacks Investment Research. For the long-term growth rate, Staff relies on multiple sources for a nominal GDP growth rate ranging from 4.39 percent to 4.58 percent[34], while I have used a GDP growth rate of 5.51 percent based on historical real GDP growth and projected inflation.

**Q. Why have you used earnings growth rates rather than dividend growth rates in the first stage of your Multi-Stage DCF analysis?**

A. There are multiple reasons why reliance on earnings per share growth rates (EPS) is more appropriate in the DCF model than *Value Line* projections of dividend per share (DPS):

[34] Staff/100, Muldoon/32-33.

1. Earnings are the fundamental determinant of a company's ability to pay dividends, and over the long-term dividend growth can only be sustained by earnings growth.[35]

2. Management decisions to conserve cash for capital investments, to manage the dividend payout for the purpose of minimizing future dividend reductions, or to signal future earnings prospects can influence dividend growth rates in near-term periods. These decisions affect the dividends and the payout ratio in the short term but are not necessarily indicative of a firm's long-term earnings growth. For example, forty S&P 500 companies suspended dividend payments in 2020 as a result of the increased uncertainty due to COVID-19.[36] These dividend suspensions occurred because companies believed earnings over the short term would decline and, therefore, elected to conserve cash to offset the financial effects of COVID-19.

3. There is significant academic research demonstrating that EPS growth rates are most relevant in stock price valuation.[37] For example, Liu, et. al. (2002) examined "the valuation performance of a comprehensive list of value drivers" and found that "forward earnings explain stock prices remarkably well" and were generally superior to other value drivers analyzed. Gleason, et. al. (2012) found that the sell-side analysts with the most accurate stock price targets were those whom the researchers found to have more accurate earnings forecasts. The use of DPS growth rates ignores the academic research demonstrating that EPS growth rates are most relevant in stock price valuation.

4. Investment analysts report predominant reliance on EPS growth projections. In a survey completed by 297 members of the Association for Investment Management and Research, the majority of respondents ranked earnings as the

[35] Eugene F. Brigham and Joel F. Houston. *Fundamentals of Financial Management*. Concise Fourth Edition, Thomson South-Western, 2004, at 317 ("Growth in dividends occurs primarily as a result of growth in earnings per share (EPS). Earnings growth, in turn, results from a number of factors, including (1) inflation, (2) the amount of earnings the company retains and invests, and (3) the rate of return the company earns on its equity (ROE).").

[36] Karen Langley, *U.S. Companies Slashed Dividends at Fastest Pace in More Than a Decade.,* Wall Street Journal (July 8, 2020).

[37] *See, e.g.,* Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return.* Financial Management, Spring 1986, at 66; James H. Vander Weide and Willard T. Carleton, *Investor growth expectations: Analysts vs. history*. The Journal of Portfolio Management, Spring, 1988; Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*. Financial Management, Summer, 1992; Advanced Research Center. Investor Growth Expectations. Summer 2004; Eugene F. Brigham, Dilip K. Shome and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity.* Financial Management, Vol. 14, No. 1, Spring, 1985; Dr. Roger A. Morin, New Regulatory Finance. Public Utilities Reports, Inc., 2006, pp. 299-303; Jing Liu, et al. *Equity Valuation Using Multiples.* Journal of Accounting Research, Vol. 40 No. 1, March 2002; C.A. Gleason, et al. *Valuation Model Use and the Price Target Performance of Sell-Side Equity Analysts.* Contemporary Accounting Research, September 2011; Boochun Jung, et. al. *Do financial analysts' long-term growth forecasts matter? Evidence from stock recommendations and career outcomes.* Journal of Accounting and Economics, Vol. 53 Issues 1-2, February-April 2012.

most important variable in valuing a security (more important than cash flow, dividends, or book value).[38]

5. Projected DPS growth rates from *Value Line* are the views of an individual analyst. In contrast, projected EPS growth rates from Yahoo! Finance and Zacks are based on consensus estimates available from multiple sources. In other words, projected EPS growth rates include the contributions of more than one analyst and thus the results are less likely to be biased in one direction or another. Moreover, the fact that projected EPS growth estimates are available from multiple sources on a consensus basis attests to the importance of projected EPS growth rates to investors when developing long-term growth expectations.

Therefore, projections of EPS growth provide a more robust estimate of total company growth since it is earnings growth that will influence DPS growth. All of these reasons are why I relied on projected EPS growth rates in the first stage of my Multi-Stage DCF analysis.

**Q. What GDP growth rates does Staff use in their Multi-Stage DCF model?**

A. As shown in Table 10 of Staff's opening testimony, Staff uses three different sources of GDP growth in their Multi-Stage DCF model: 1) a blended growth rate of 4.58 percent based on 20 percent weight given to the BEA nominal historical GDP growth rate of 5.10 percent and the following sources of projected GDP: Energy Information Administration (EIA); Organization for Economic Co-operation and Development (OECD); Social Security Administration (SSA); and Congressional Budget Office (CBO); 2) a projected growth rate of 4.46 percent based on the CBO long-term 20-year budget outlook; and 3) a projected 20-year nominal GDP growth rate of 4.39 percent from the SSA.

[38] Stanley B. Block, *A Study of Financial Analysts: Practice and Theory*. Financial Analysts Journal, July/August 1999.

**Q. Are the GDP growth rates relied on by Staff witness Muldoon in the current proceeding consistent with the GDP growth rates relied on by Staff witness Muldoon in the Company's last rate proceeding?**

A. No, they are not. Staff witness Muldoon has made three changes to the GDP growth rates on which are relied on in the current proceeding from the GDP growth rates that were relied on in the Company's last rate proceeding, docket UE 399:

1. As shown in Figure 9 below, Staff witness Muldoon changed the weighting on the five GDP growth rates that were relied on to estimate Staff's composite GDP growth rate. In the current proceeding, Staff witness Muldoon placed 20 percent weight on the BEA historical nominal GDP growth rate and the four projected GDP growth rates from the OECD, SSA, EIA and CBO while in docket UE 399, Staff witness Muldoon placed 50 percent weight on the BEA historical nominal GDP growth rate and 12.5 percent weight on the four projected GDP growth rates from PricewaterhouseCooper, EIA, SSA and CBO.

**Figure 9: Staff's Composite GDP Growth Rate - Current Proceeding vs. Docket No. UE 399[39]**

| | UE 399 | | | UE 433 | | |
|---|---|---|---|---|---|---|
| **GDP Growth Rate Source** | **GDP Growth Rate** | **Weighted** | **Weighted Rate** | **GDP Growth Rate** | **Weighted** | **Weighted Rate** |
| PricewaterhouseCooper | 4.68% | 12.50% | 0.59% | N/A | N/A | N/A |
| Organization for Economic Co-operation and Development | N/A | N/A | N/A | 4.24% | 20.00% | 0.85% |
| Energy Information Administration (EIA) | 4.38% | 12.50% | 0.55% | 4.69% | 20.00% | 0.94% |
| Social Security Administration | 4.27% | 12.50% | 0.53% | 4.39% | 20.00% | 0.88% |
| Congressional Budget Office | 3.87% | 12.50% | 0.48% | 4.46% | 20.00% | 0.89% |
| BEA Nominal Historical | 4.95% | 50.00% | 2.47% | 5.10% | 20.00% | 1.02% |
| **Composite GDP Growth Rate** | | | **4.62%** | | | **4.58%** |

2. As shown in Figure 10, in docket UE 399, Staff witness Muldoon developed a scenario where Staff relied only on the BEA historical nominal GDP growth rate in their Multi-Stage DCF model; however, in the current proceeding, Staff witness Muldoon instead decides to rely on the projected GDP growth rate from the SSA.

3. As also shown in Figure 10, in docket UE 399, Staff witness Muldoon developed a scenario where Staff relied on my GDP growth rate in the Multi-Stage DCF model;

[39] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 399, Staff/100, Muldoon/30 (June 22, 2022); and Staff/100, Muldoon/33.

however, Staff witness Muldoon has not calculated a similar scenario in the current proceeding.

**Figure 10: Staff's GDP Growth Rates - Current Proceeding vs. Docket No. UE 399[40]**

| | UE 399 | UE 433 |
|---|---|---|
| Composite GDP Growth Rate | 4.62% | 4.58% |
| Congressional Budget Office | 4.00% | 4.46% |
| Social Security Administration | N/A | 4.39% |
| BEA Nominal Historical | 4.95% | N/A |
| Company's GDP Growth Rate | 5.49% | N/A |

Staff witness Muldoon has not provided any support for the changes to the selection of the GDP growth rates between the docket UE 399 and the current proceeding. Since the historical and projected GDP growth rates have generally increased since docket UE 399 as shown in Figure 9 and Figure 10, it appears that each of the three changes Staff witness Muldoon has made would result in a decrease in the results of Staff's Multi-Stage DCF model. Therefore, it is reasonable to conclude that Staff witness Muldoon changed the approach for selecting the GDP growth rates to produce a desired cost of equity result.

**Q. What GDP growth rate did Staff rely on to develop their recommended range?**

A. Staff relied on their Multi-Stage DCF result using the projected GDP growth rate from the SSA as the low-end of their recommended range while they relied on their Multi-Stage DCF results using the composite GDP growth rate to set the high-end of their recommended range.[41] For example, the lower boundary of Staff's range of 9.09 percent is calculated based on their proxy group and projected GDP growth rate from the SSA of 4.39 percent, which produces a Multi-Stage DCF result of

[40] *Id.*
[41] Source: Staff/104, Muldoon/1.

9.08 percent, which Staff then adjusts for leverage using the Hamada-equation to a return of 8.97 percent, plus flotation costs of 12.5 basis points to arrive at the 9.09 percent return. Similarly, the upper boundary of Staff's range of 9.55 percent is calculated based on their proxy group and their composite GDP growth rate, which produces a Multi-Stage DCF result of 9.54 percent, which Staff then adjusts for leverage using the Hamada-equation to a return of 9.43 percent, plus flotation costs of 12.5 basis points to arrive at the 9.55 percent return.

**Q. Is Staff witness Muldoon's approach for developing Staff's recommended range consistent with the approach relied on to develop Staff witness Muldoon's recommended range in docket UE 399?**

A. No. In docket UE 399, Staff witness Muldoon relied solely on the results of the Multi-Stage DCF model using Staff witness Muldoon's historical GDP growth rate of 4.95 percent to develop Staff's range of reasonable ROEs and ROE recommendation for PacifiCorp.[42]

**Q. How would Staff witness Muldoon's recommended range in this proceeding have changed if the results of Staff's Multi-Stage DCF model using Staff's BEA historical nominal GDP growth rate was relied on as Staff witness Muldoon did in the Company's last rate proceeding?**

A. As shown in Exhibit PAC/2214**,** when the BEA nominal historical GDP rate is used, Staff's Multi-Stage DCF models (Model X - 30-year Three-stage Discounted Dividend Model with Terminal Valuation based on Growing Perpetuity and Model Y - 30-year Three-stage Discounted Dividend Model with Terminal Valuation Based

[42] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 399, Staff/104 Muldoon/1 (June 22, 2022).

on P/E Ratio) produce an ROE range using both Staff's and my proxy groups[43] of 9.47 percent to 9.93 percent. After the application of Staff's Hamada adjustment and flotation cost adjustment, the range of reasonableness would be 9.18 percent to 9.94 percent with a midpoint of 9.56 percent. Therefore, Staff's approach to determining their ROE recommendation in docket UE 399 provides support for the Company's revised ROE request of 9.65 percent.

**Q. Staff witness Muldoon did not develop a scenario of Staff's Multi-Stage DCF model using your GDP growth rate in the current proceeding; however, has Staff witness Muldoon considered your GDP growth rate in prior proceedings?**

A. Yes. As noted above, in docket UE 399, while Staff witness Muldoon did not rely on the results to determine Staff's recommended ROE range, Staff witness Muldoon did develop a Multi-Stage DCF scenario that relied on my GDP growth rate of 5.49 percent. Furthermore, in docket UE 374 for PacifiCorp in 2020, Staff witness Muldoon relied on my GDP growth rate of 5.53 percent in Staff's Multi-Stage DCF analysis to establish the upper boundary of Staff's range of reasonable ROEs of 9.39 percent.[44] It is unclear why Staff witness Muldoon has not considered a scenario of Staff's Multi-Stage DCF model in the current proceeding.

[43] I relied on the proxy group used to calculate my updated results which is the same proxy group I relied on in my direct testimony except I have excluded ALLETE, Inc. since ALLETE, Inc. is currently being acquired.
[44] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Staff/205, Muldoon-Enright /1 (June 4, 2020).

**2. Hamada Equation**

**Q. Do you agree with the Hamada equation Staff used to adjust the return produced by the Multi-Stage DCF model for differences in leverage between PacifiCorp and the proxy group companies?**

A. No, I do not. I have two concerns with Staff's application of the Hamada equation. First, I disagree with the equity risk premium that Staff relied on to calculate the Hamada adjustment. Staff relied on an equity risk premium of 4.50 percent which they note is based on the historical market risk premium calculated by Ibbotson.

Second, Staff's use of the Hamada Equation relies on the book value of debt and equity for each of the proxy group companies at the holding company level as published by *Value Line*, instead of the market value of debt and equity as required to estimate the Hamada Equation.

**Q. Please explain your disagreement with the equity risk premium used in Staff's Hamada equation.**

A. There are several reasons why I disagree with the equity risk premium used in Staff's Hamada equation. First, the equity risk premium relied on by Staff in the Hamada equation is inconsistent with the equity risk premium they use in their CAPM. Staff has relied on the historical risk premium as estimated by Ibbotson of 4.50 percent in their Hamada equation but an equity risk premium of 4.73 percent in their CAPM analysis. While I will discuss in more detail below why I disagree with Staff's calculation of the risk premium of 4.73 percent in their CAPM, they should have been consistent and also relied on a risk premium of 4.73 percent in their Hamada

equation. Staff provides no explanation as to why they assumed a different risk premium for the Hamada equation than the CAPM.

Second, I disagree with the use of the historical market risk premium because it fails to consider the inverse relationship between interest rates and the market risk premium. As shown in my Bond Yield plus Risk Premium analysis, as interest rates decrease, the market risk premium increases. Lastly, it is not clear what time period Staff used to estimate the historical risk premium from Ibbotson; however, Staff's calculation does not appear to incorporate recent data since their risk premium estimate has not changed from the historical risk premium they reported in either their opening testimony in PacifiCorp's last rate case, docket UE 399[45] or their opening testimony in docket UE 374 for PacifiCorp, in June 2020.[46]

**Q. How does Staff apply the Hamada equation?**

A. The Hamada equation allows an analyst to first "unlever" beta to remove the effect of the debt ratio of a company and then "relever" beta at different debt ratios to examine the effect of changes in the debt ratio on the cost of equity produced by the CAPM. The Hamada equation is as follows:[47]

$$\beta_l = \beta_u [1 + (1 - T)\frac{D}{E} \quad [1]$$

Where:

$\beta_l$ = Levered beta of a company

$\beta_u$ = Unlevered beta of a company

[45] [45] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 399, Staff/102, Muldoon /5 (June 22, 2022).
[46] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Staff/205, Muldoon, Enright/1 (June 4, 2020).
[47] *See*, Villadsen, Vilbert, Harris and Kolbe, *Risk and Return for Regulated Utilities,* 2017, at 146-154; and Brealey, Myers, and Allen, *Principles of Corporate Finance,* 13th Ed., 2020, at 452-462.

$T$ = Corporate income tax rate

$D$ = Market value of debt

$E$ = Market value of equity

In their analysis, Staff is unlevering the betas of each of the proxy group companies to remove the effect of the debt ratios of the proxy group companies and then relevering the betas for each proxy group company to reflect the Company's proposed capital structure. Staff then applies the difference between the *Value Line* betas and the relevered betas to their historical risk premium of 4.50 percent to develop their Hamada adjustment for each of the proxy group companies. Finally, the proxy group average Hamada adjustment is applied to their Multi-Stage DCF results.

**Q. How does Staff's use of the book value of debt and equity affect their estimated Hamada adjustment?**

A. As shown in Equation [1] above, levered beta is a function of the market debt-to-equity ratio. Therefore, the use of the book value of debt and equity can have a substantial effect on the debt-to-equity ratio used to unlever and relever beta if the market value of debt and equity deviates significantly from the book value.

**Q. Have you estimated the equity ratio and debt ratio for Staff's proxy group based on the market value of debt and equity?**

A. Yes. To estimate the Hamada equation, Staff relies on an average debt ratio of 51.25 percent and a common equity ratio of 48.44 percent for their proxy group, both of which are based on the book value of debt and equity for each of their proxy group companies. Because the Company's proposed debt ratio (i.e., 49.99 percent) is lower than average debt ratio of their proxy group (i.e., 51.25 percent), their application of

the Hamada Equation results in a downward adjustment to their Multi-Stage DCF results of 11 basis points. However, as shown in Exhibit PAC/2211 had Staff correctly relied on the market value of debt and equity for each of their proxy group companies, they would have estimated an average debt ratio for their proxy group of 43.86 percent, not 51.25 percent. Since the market value debt ratio for the proxy group of 43.86 percent is lower than the Company's proposed debt ratio of 49.99 percent, the Hamada Equation when specified correctly would imply that Staff's Multi-Stage DCF results percent should increase, not decrease, to reflect the increased financial risk associated with the Company's proposed debt ratio relative to the proxy group. Therefore, Staff's Multi-Stage DCF results will understate the cost of equity for PacifiCorp.

**Q. Have you adjusted Staff's Multi-Stage DCF analysis to address your concerns with their application of the Hamada equation?**

A. Yes. I revised Staff's Hamada Adjustment to: 1) rely on the equity risk premium of 4.73 percent that Staff used in their CAPM analysis; and 2) use the market value of debt and equity as opposed to the book value of debt and equity. As shown in Exhibit PAC/2214, by making these reasonable adjustments to Staff's Multi-Stage DCF analysis, their recommended ROE range increases from 9.09 percent to 9.55 percent to 9.67 percent to 10.12 percent. In addition to being below the low end of the range of my analyses, the Company revised requested ROE of 9.65 percent is also below the low-end of the adjusted range of Staff's analyses of the investor required return. While Staff does not take into consideration the relative business risks of the Company and the proxy group, based on the analysis discussed in my direct

testimony, the Company's overall risk profile is not below average and therefore, its revised proposed ROE is conservative.

### 3. Adjustments to Staff's Multi-Stage DCF Analysis

**Q. Have you developed a version of Staff's Multi-Stage DCF analysis that reflects each of your recommended adjustments?**

A. Yes, I have. I adjusted Staff's Multi-Stage DCF analysis to reflect the following[48]:

1. Calculate the Hamada adjustment to rely on the equity risk premium of 4.73 percent that Staff used in their CAPM analysis and rely on the market value of debt and equity as opposed to the book value of debt and equity.

2. Develop the range of reasonable ROEs for PacifiCorp based on the range of Multi-Stage DCF results using Staff's BEA historical GDP growth rate of 5.10 percent and Staff's and my proxy groups[49], which is consistent with the approach Staff witness Muldoon relied on to develop Staff's ROE recommendation in PacifiCorp's last rate case, docket UE 399.

As shown in Figure 11, (see also Exhibit PAC/2214), as a result of these reasonable adjustments, the results of Staff's Multi-Stage DCF analysis increase to a range of 10.00 percent to 10.52 percent, with an approximate midpoint of 10.26 percent.

**Figure 11: Summary of Adjustments to Staff's Multi-Stage DCF Analysis[50]**

| | Midpoint | ROE Range |
|---|---|---|
| As Filed | 9.32% | 9.09% - 9.55% |
| Adjusted (Historical GDP Rate Only) | 9.56% | 9.18% - 9.94% |
| Adjusted (Hamada Adj. Only) | 9.89% | 9.67% - 10.12% |
| Adjusted (Hist. GDP Growth & Hamada) | 10.26% | 10.00% - 10.52% |

[48] While I disagree with the proxy group relied on by Staff for the reasons discussed in Section V.A above, the differences between my and Staff's proxy groups are not the primary driver of the differences in our results. As a result, I have not developed a scenario of his Multi-Stage DCF model with proposed adjustments to his proxy group.
[49] I relied on the proxy group used to calculate my updated results which is the same proxy group I relied on in my direct testimony expect I have excluded ALLETE, Inc. since ALLETE, Inc. is currently being acquired.
[50] Multi-Stage DCF results include Hamada and Flotation Cost Adjustments.

**4. Reliance on Multi-Stage DCF Model**

**Q. What do you conclude about the results of the DCF model under current market conditions?**

A. As discussed in my direct testimony and Section III above, the yields on long-term government bonds exceed the dividend yields of utilities which is counter to the historical relationship.[51] Since long-term government bond yields are expected to remain elevated, equity analysts and investors expect the utility sector to underperform as the spread between long-term government bond yields and utility dividend yields normalizes towards the historical average. If the prices of utility stocks decline, then the DCF model, which relies on historical averages of share prices to calculate the dividend yield, is likely to understate the dividend yield and, thus, the cost of equity. Therefore, Staff's recommended ROE range of 9.09 percent to 9.55 percent based solely on the results of their Multi-Stage DCF analysis is most likely understating investors' return requirements over the period that PacifiCorp's rates will be in effect. Moreover, current and prospective market conditions support consideration of other ROE estimation models such as the CAPM, and Risk Premium, which may better reflect expected market conditions during the period that PacifiCorp's rates will be in effect.

**Q. Has the Commission noted that it is important to recognize the results of multiple ROE estimation models?**

A. Yes. As discussed in my direct testimony, while the Commission has generally relied on the Multi-Stage DCF model, while using the Single-Stage DCF and the CAPM

[51] PAC/400, Bulkley/22-25.

methodologies to test the reasonableness of the Multi-Stage DCF results, the Commission has previously considered the results of many ROE estimation models and determined, based on the results of those models, whether or not to place any weight on the model in its final determination.[52]

## C. Alternative ROE Methodologies

**Q. Does Staff use any alternative ROE methodologies to test the reasonableness of the Multi-Stage DCF model results?**

A. Yes. Staff has considered alternative ROE methodologies, such as the Constant Growth DCF model and the CAPM analysis to test the reasonableness of their Multi-Stage DCF model results.[53] However, Staff has not placed any weight on the results of these alternative methodologies in establishing their recommended ROE range.

**Q. Why do you believe it is important to place weight on the results of multiple methodologies?**

A. As explained in my direct testimony, investors consider the results of multiple methodologies in order to inform their view of the cost of equity, including the DCF model, the CAPM, and the risk premium analysis.[54] This is particularly important because each ROE estimation model has its own strengths and shortcomings. When the results of one model cannot be corroborated by the results of alternative models, it is reasonable and appropriate to consider the individual and collective results of multiple methods to establish the return on equity.

[52] PAC/400, Bulkley/32.
[53] Staff/100, Muldoon/21-22.
[54] PAC/400, Bulkley/29-32.

**1. Constant Growth DCF**

**Q. Why is it reasonable to use the Constant Growth DCF model to estimate the cost of equity for regulated utilities?**

A. As discussed in my direct testimony, one of the assumptions of the Constant Growth DCF model is a constant growth rate for earnings and dividends in perpetuity.[55] Regulated utilities are in a mature industry and therefore the growth rates for this industry are not likely to be as volatile as start-up companies, or companies that experience greater volatility in the competitive market. Therefore, it is a reasonable to rely on the Constant Growth DCF. In fact, the Constant Growth model was developed by Professor Myron Gordon in the 1960s for the purpose of estimating the cost of equity for companies that pay dividends, that have steady growth rates and which operate in mature industries. The Multi-Stage DCF model was developed later, as a variation on the Constant Growth DCF model, in order to allow for the possibility that the near-term growth rate for a company would change over the longer term. However, for regulated utilities, the near-term growth rate is generally sustainable over the longer term because these are mature companies with relatively stable demand. My current concern with the DCF model (both Constant Growth and Multi-Stage) is that given that investors expect the utility sector to underperform, the DCF model is currently understating the cost of equity over the near-term or the period that PacifiCorp's rates will be in effect.

[55] PAC/400, Bulkley/33.

**Q. Do you agree with Staff's specification of the Constant Growth DCF model?**

A. No. There are two primary issues with Staff's Constant Growth DCF model. First, Staff has relied solely on projected dividend growth rates provided by *Value Line*. As I discussed above, analysts' projected earnings growth rates are the more appropriate estimate of growth in the Constant Growth DCF model because projected dividend growth rates are: 1) only sustained by earnings growth; and 2) susceptible to changes in management decisions which do not reflect the long-term growth prospects of firm. Moreover, the use of earnings growth is supported by the academic literature. Finally, Staff's sole reliance on projected dividend growth rates is not consistent with Staff's specification of the Multi-Stage DCF model where Staff also considered projected earnings growth rates from *Value Line*.

Second, because Staff has relied on only one growth rates source, projected dividend growth rates provided by *Value Line,* they have assumed negative estimates of projected dividend growth in perpetuity, which is incompatible with the use of the Constant Growth DCF model. For example, as shown in Exhibit Staff/106, Staff relies on projected dividend growth rates from *Value Line* of -2.4 percent and -2.6 percent for PPL and SRE, respectively.

**Q. Why are negative growth rates incompatible with the use of the constant growth DCF model?**

A. The assumption that negative growth rates can be used in the constant growth DCF model is incorrect for two reasons. First, the assumption of a negative growth rate in perpetuity would assume that PPL and SRE would at some point discontinue operations, which, given that both PPL and SRE have positive EPS growth rates from

both *Value Line*, is an unreasonable assumption. Second, relying on a projected dividend growth rate of -2.4 percent for PPL results in a cost of equity estimate of 1.44 percent while relying on a dividend growth rate of -2.6 percent for SRE results in a cost of equity estimate of 0.85 percent. As shown in Figure 2, these results would be 306 to 365 basis points less than the current 30-day average yield on the 30-year Treasury bond of 4.50 percent as of June 28, 2024, and, therefore, would clearly not provide an adequate risk premium to compensate investors for the added risk of equity. These results are out of line with investors' expected return requirements. Investors would require a substantial risk premium to invest in PPL and SRE given that the negative growth rate implies the company would discontinue operations. It is evident from this example, that Staff should have: 1) relied on projected EPS growth rates in addition to projected dividend growth so Staff was not relying on only one growth rate source; and 2) exclude negative projected growth rates from their constant growth DCF analysis.

**Q. Have you adjusted Staff's Constant Growth DCF analysis?**

A. Yes, I have. I adjusted Staff's Constant Growth DCF analysis to:[56] 1) exclude the projected dividend growth rates from Value Line of -2.4 percent and -2.6 percent for PPL and SRE, respectively; and 2) rely on projected EPS growth rates from *Value Line*, Yahoo! Finance and Zacks Investment Research in additional to the projected dividend growth rates from *Value Line*.[57] As shown in Exhibit PAC/2210), by making

[56] While I disagree with the proxy group relied on by Staff for the reasons discussed in Section V.A above, the differences between my and Staff's proxy groups are not the primary driver of the differences in our results. As a result, I have not developed a scenario of his Constant Growth DCF model with proposed adjustments to their proxy group.

[57] I excluded the projected EPS growth rate of 17.21 percent for PPL as reported by Yahoo!. It is not reasonable to assume a growth rate of 17.21 percent in perpetuity as required by the constant growth DCF.

reasonable adjustments to Staff's Constant Growth DCF analysis, the results using their proxy group increase 123 basis points from 8.40 percent to 9.64 percent.

The adjusted DCF result of 9.64 percent is slightly greater than the high-end of their range of reasonableness of 9.55 percent based on the results of their Multi-Stage DCF model including the Hamada and Floatation cost adjustments. Furthermore, if the corrected Hamada adjustment using the market value of debt and equity (46 basis points for Staff's proxy group) and Flotation cost (12.5 basis points) adjustment are added to the adjusted Constant Growth DCF results of 9.64 percent, the resulting ROE is 10.22 percent which is which provides further support that the Company's revised request of 9.65 percent is conservative.

**Q. Did Staff apply the Hamada and Flotation cost adjustments to their Constant Growth DCF results?**

A. No. Further, Staff did not provide an explanation as to why the Hamada and Flotation cost adjustments were not applied to their Constant Growth DCF results. It would stand to reason that if Staff determined the adjustments were appropriate for the Multi-Stage DCF model that each adjustment should also be applied to the Constant Growth DCF model.

**2. CAPM and Risk Premium**

**Q. Please explain why you believe it is also appropriate to place weight on the results of the CAPM and Risk Premium approaches.**

A. Risk premium-based models are also commonly used by investors to estimate the cost of equity. Both the CAPM and Risk Premium approaches rely on a risk-free rate (i.e., 30-year Treasury bonds) plus a risk premium to compensate investors for the

additional risks associated with owning common equity. Risk premium-based models provide another view on the cost of equity based on the historical relationship between risk-free rates and equity returns. In the CAPM, beta is the measure of risk for a specific company or industry relative to the broad market. Research has shown that beta tends to understate the expected return for companies such as regulated utilities that typically have beta coefficients less than 1.0, while overstating the expected return for companies with betas greater than 1.0. The CAPM and Risk Premium results in my direct testimony indicate that the cost of equity for regulated electric utilities is slightly higher than the ROE estimates that are being produced by the DCF models at this time. This suggests that it is not appropriate for the Commission to base its decision for PacifiCorp solely on the results of the Multi-Stage DCF model, when other well-regarded models do not fully corroborate the results of the Multi-Stage DCF model.

**Q. Do you have any concerns with Staff's estimate of the market risk premium (MRP)?**

A. Yes, I do. As shown in Exhibit Staff/105, Staff calculates the market risk premium as the difference between the 30-year geometric average return on the S&P 500 Index and the yield on the 30-year Treasury bond yield as of February 24, 2024. My primary concern with Staff's calculation of the MRP is their selection of the market return. First, as shown in Attachment A in Exhibit PAC/2222, Staff estimates their 30-year geometric average return for the S&P 500 Index as an average of the 30-year geometric average price return and the 30-year geometric average total return (*i.e.*, includes dividends and changes in price). Staff has not provided any support for why

the return on the S&P 500 should be calculated as an average of the 30-year geometric average price return and the 30-year geometric average total return. It is the total return that provides the more appropriate assessment of the performance of the S&P 500 Index. In fact, Staff estimates a 30-year geometric average total return for the S&P 500 Index of 10.15 percent which is significantly greater than the 30-year geometric average market return of 9.08 percent calculated as the average of the 30-year geometric average price return and the 30-year geometric average total return. Therefore, Staff's decision to rely on an average of the 30-year geometric average price return and the 30-year geometric average total return understates the actual performance of the S&P 500 Index over the 30-year period of 1994 through 2023. Further, Staff's estimate of the 30-year geometric average total return for the S&P 500 Index of 10.15 percent is generally consistent with the geometric average return for the S&P 500 Index over the 30-year period of 1994 through 2023 of 10.31 percent as reported by *Kroll*. Second, Staff has incorrectly relied on the geometric mean market return as opposed to the arithmetic mean market return.

**Q. Why is it inappropriate to consider the historical geometric mean market return?**

A. Geometric and arithmetic means are used for different purposes. The geometric mean is the compound rate that equates a beginning value to its ending value. It is used to determine the exact rate of compounded return between a specific starting and ending point. The arithmetic mean, which is the appropriate calculation to be used for this purpose, is the simple average of single period rates of return and best approximates the uncertainty associated with returns from year to year. The important distinction

between the two methods is that the arithmetic mean assumes that each periodic return is an independent observation and, therefore, incorporates uncertainty into the calculation of the long-term average. In contrast, the geometric mean does not incorporate the same degree of uncertainty because it assumes that returns remain constant from year to year. Cooper (2006) reviewed the literature on the topic and noted the following rationale for using the arithmetic mean:

> Note that the arithmetic mean, not the geometric mean is the relevant value for this purpose. The quantity desired is the rate of return that investors expect over the next year for the random annual rate of return on the market. The arithmetic mean, or simple average, is the unbiased measure of the expected value of repeated observations of a random variable, not the geometric mean.…[The] geometric mean underestimates the expected annual rate of return.[58]

Furthermore, Pratt and Grabowski note the following in their review of the literature:

> The choice between which average to use is a matter of disagreement among practitioners. The arithmetic average receives the most support in the literature, though other authors recommend a geometric average. The use of the arithmetic average relies on the assumption that (1) market returns are serially independent (not correlated) and (2) the distribution of market returns is stable (not time-varying). Under these assumptions, an arithmetic average gives an unbiased estimate of expected future returns assuming expected conditions in the future are similar to conditions during the observation period. Moreover, the more observations available, the more accurate will be the estimate.[59]

[58] Ian Cooper, *Arithmetic versus geometric mean estimators: Setting discount rates for capital budgeting.* European Financial Management *2.2*. 1996, at 158.
[59] Shannon P. Pratt and Roger J. Grabowski, *Cost of Capital: Applications and Examples*. Wiley, 2008, at 96.

**Q. What is the arithmetic mean return for the S&P 500 Index over the 30-year period of 1994 to 2023?**

A. The historical arithmetic return of the S&P 500 Index from 1994–2023 as reported by *Kroll* is 11.94 percent[60] which is much greater than the geometric return of the S&P 500 of 9.08 percent calculated by Staff.

**Q. Do you agree with Staff that your estimate of the market return is "inflated" which "skews" your CAPM results upward?[61]**

A. No, I do not. First, as noted above, the arithmetic average market return from 1994-2023 is 11.94 percent as reported by *Kroll* which is generally consistent with the market return that I relied on in my direct testimony of 12.56 percent. Second, as shown in Figure 10 of my direct testimony, reviewing the range of annual equity returns that have been observed over the past century, in 50 out of the past 97 years (or roughly 52 percent of observations), the realized equity return was at least 12.56 percent or greater. Therefore, my estimate of the market return is more than reasonable considering the historical returns achieved by Large Company Stocks.

**Q. Has Staff relied on your market return to develop their CAPM in a prior proceeding?**

A. Yes. In docket UE 374 for PacifiCorp, Staff, estimated their CAPM analysis using my estimate of the market return which was 12.60 percent.[62] The 12.60 percent market return estimate that I and Staff relied on in docket UE 374 for PacifiCorp is generally consistent with the 12.56 percent market return that I relied on in my CAPM in my

[60] Source: Kroll, Cost of Capital Navigator, data as of Dec. 31, 2023.
[61] Staff/100, Muldoon/26.
[62] *In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Staff/206, Muldoon, Enright /1 (June 4, 2020).

direct testimony in the current proceeding. Therefore, it is not reasonable for Staff to conclude that my market return is "inflated" when they have relied on a similar market return in docket UE 374 for PacifiCorp in 2020.

**Q. Have you adjusted Staff's CAPM analysis?**

A. Yes, I have. I developed two separate scenarios that adjust the market return relied on in Staff's CAPM analysis.[63] While I disagree with the use of the geometric average market return for the reasons discussed above, the first CAPM scenario relies on the geometric average return for the S&P 500 over the 30-year period of 1994 through 2023 of 10.31 percent as reported by *Kroll* as the estimate of the market return. As shown in Exhibit PAC/2216, this increases Staff's CAPM result using their proxy group from 8.67 percent to 9.79 percent. The second CAPM scenario relies on the arithmetic average return of the S&P 500 Index from 1994–2023 of 11.94 percent as reported by *Kroll*. As shown in Exhibit PAC/2216, this adjustment would increase the CAPM result for Staff's proxy group from 8.67 percent to 11.28 percent.

**Q. What is your conclusion regarding Staff's Constant Growth DCF and CAPM analyses?**

A. My primary conclusion is that when reasonable adjustments are applied to Staff's Constant Growth DCF, the results increase to 9.64 percent while reasonable adjustments to Staff's CAPM analyses results in a range of 9.79 percent to 11.28 percent. The adjusted results clearly indicate that Staff's range of reasonableness of 9.09 percent to 9.55 percent and midpoint of 9.30 percent which are

[63] While I disagree with the proxy group relied on by Staff for the reasons discussed in Section V.A above, the differences between Staff's proxy group and my proxy group are not the primary driver of the differences in our results. As a result, I have not developed a scenario of his CAPM model with proposed adjustments to Staff's proxy group.

based on the results of their Multi-Stage DCF analysis understate the cost of equity during the period that PacifiCorp's rates will be in effect. Finally, the adjusted Constant Growth DCF and CAPM results provide additional support that the Company's revised request of 9.65 percent is conservative.

## D. Business Risks

**Q. Did Staff consider the relative risks between the Company and the proxy group?**

A. No. The only additional considerations Staff outlines in their testimony, beyond the results of their models, is the Company has filed three rate cases in the past five years which they contend may reduce regulatory lag and financial risk by improving certain credit metrics.[64] According to Staff, the Commission could determine that the reduced regulatory lag as a result of the frequent rate cases warrants "a ten percent lower ROE within a range of reasonable ROEs."[65]

**Q. What is your response?**

A. Staff appears to conclude that the Company's business risk is reduced because the Company has filed three rate cases in the past five years which reduces regulatory lag. According to Staff, the reduction in the Company's risk as a result of "frequent" rate case filings could warrant a reduction in the ROE. However, it is not reasonable to conclude that simply because a company files frequent rate cases that its ROE should be reduced. The appropriate approach is to compare the regulatory risk of PacifiCorp to the regulatory risk of the proxy group being used to develop the ROE to determine if PacifiCorp has greater regulatory risk than the proxy group. As discussed in my direct testimony:

[64] Staff/100, Muldoon/15-16.
[65] *Id.,* at 16.

- Considering the regulatory adjustment mechanisms as shown in Exhibit PAC/413, many of the companies in the proxy group have more timely cost recovery through comprehensive fuel cost recovery mechanisms, forecasted test years, capital cost recovery trackers and non-volumetric rate design than PacifiCorp has in Oregon.

- The RRA jurisdictional ranking and S&P credit supportiveness ranking for Oregon is below the average for group.

Therefore, for all these reasons, I concluded that the Oregon regulatory framework has somewhat greater risk than the jurisdictions in which the utility operating subsidiaries of the proxy group companies provide service. Given Staff has not provided any analysis to compare the regulatory risk of the Company relative to the proxy group, Staff is unable to conclude that the Company's ROE could be reduced due to "frequent" rate case filings.

## VI. RESPONSE TO AWEC

**Q. How does AWEC develop their recommended ROE for PacifiCorp in this proceeding?**

A. AWEC relies on my proxy group,[66] and conducts two constant growth DCF analyses and two multi-stage DCF analyses (*i.e.*, each using a different a constant growth DCF and multi-stage DCF), a CAPM, and an ECAPM analysis using this proxy group. Based on the results of these analyses, AWEC recommends a range of reasonableness for the Company's ROE of 8.70 percent to 9.60 percent and recommends an ROE of 9.25 percent with a proposed capital structure that is composed of 44.35 percent equity, 0.01 percent preferred stock and 44.99 percent debt.[67]

[66] AWEC/200, Kaufman/56.
[67] AWEC/200, Kaufman/50.

**A. Multi-Stage DCF Analyses**

**Q. How does AWEC develop their Multi-Stage DCF analyses?**

A. AWEC relies on the form of the multi-stage DCF model that I used in my direct testimony, making two changes; 1) revising the long-term growth rate used in my analysis and 2) changing the year in which the model reverts to long-term growth from year 6 to year 25. The remainder of the assumptions in AWEC's multi-stage DCF model are consistent with the assumptions used in my direct testimony, using the annualized dividends and 30-day, 90-day, and 180-day average stock prices of the proxy group companies as of November 30, 2023. AWEC stated that the use of my market data was to limit the differences between my analysis, filed in my direct testimony and AWEC's analysis and to ensure that the data used was for a consistent time period. AWEC indicated that it would not be appropriate to update stock prices without also updating growth forecasts and beta estimates.[68]

**Q. How does AWEC calculate the long-term growth rate used in their Multi-Stage DCF model?**

A. AWEC estimates a terminal growth rate of 3.94 percent, which is the average projected growth in GDP from 2033 to 2050 which AWEC states is based on the S&P Global Market Intelligence projected GDP as of May 9, 2024, and an inflation factor that is calculated based on first quarter 2023 projection of inflation factors from IHS Global Insights.

[68] AWEC witness Kaufman does not have subscriptions to the Bloomberg and Value Line data necessary to perform their own updated analysis.

**Q. Is AWEC witness Kaufman's calculation of the long-term growth rate as specified in their analysis in this proceeding consistent with the methodology AWEC witness Kaufman has relied upon in other recent proceedings?**

A. No. AWEC witness Kaufman filed testimony approximately two months prior to AWEC testimony being filed in the current proceeding in the Sierra Pacific Power Company (Sierra) general rate case in Nevada where AWEC witness Kaufman established two estimates of long-term GDP growth. The first was based on the 30-day average yield on the 30-year Treasury bond of 4.77 percent, which is consistent with the yield on the treasury bonds that was filed in my direct testimony.[69] Therefore, it is curious that AWEC witness Kaufman did not rely on this same scenario in the current proceeding.

The second growth rate that AWEC witness Kaufman relied upon was based on AWEC witness Kaufman's estimate of the U.S. Congressional Budget Office GDP growth rate.[70] In that proceeding, AWEC witness Kaufman indicated that the U.S. CBO GDP forecast was reliable, unbiased and highly vetted.[71]

**Q. Is the projected GDP growth rate that AWEC developed in this proceeding consistent with the remainder of the data used in their analysis?**

A. No. While AWEC recognizes the need for consistency in the market data used in the analytical models, their GDP growth rate projection is based on projections from several different time periods, none of which are consistent with the price, dividend

[69] *See* PAC/407.
[70] *In the Matter of the Application by Sierra Pacific Power Company d/b/a/ NV Energy, filed pursuant to NRS 704.110(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric customers,* Public Utilities Commission of Nevada, Docket No. 24-02026, Prepared Direct Testimony of Lance D. Kaufman, Exhibit Kaufman-Direct-3, at 13-14 (May 21, 2024).
[71] *Id.*

and growth rate data that AWEC uses in their DCF analyses. Based on their own admission of the importance of maintaining a consistent data set, AWEC's GDP growth rate should not be relied upon for this reason. As noted previously, AWEC's price, dividend and growth rate data is as of November 30, 2023. AWEC's projected GDP estimate is as of May 9, 2024, and their estimates of inflation are based on data as of the first quarter of 2023. The underlying market conditions related to these time periods, particularly in the current interest rate and inflationary environment, are entirely inconsistent and cannot be used in the same model.

**Q. Has Staff relied on the CBO as a measure of long-term GDP growth?**

A. Yes. While I have discussed the issues with Staff's GDP growth rate estimates previously, Staff developed several estimates of GDP growth, including the CBO GDP growth rate, which as noted previously, AWEC witness Kaufman recently endorsed. The range of growth rate estimates developed by Staff are significantly higher than the estimate developed by AWEC in this proceeding. As shown in Table 10 of Staff's testimony, the range of GDP growth estimates developed by Staff is from 4.39 percent to 5.10 percent. the CBO estimate is 4.46 percent.[72] Further, this CBO estimate is generally consistent with the yield on the 30-year Treasury bond as shown in PAC/2205.

[72] Staff/100, Muldoon/32.

**Q. How would the results of AWEC witness Kaufman's Multi-Stage DCF analysis change if the average yield on the 30-year Treasury bond was relied on as an estimate of GDP growth?**

A. If AWEC witness Kaufman had relied on the 4.77 percent yield on the 30-year Treasury bond as the estimate of GDP growth, consistent with one of AWEC witness Kaufman's scenarios in the Sierra case referenced previously, and consistent with the average yield on the 30-year Treasury bond as of November 30, 2023, which is the time period of the remainder of the market data in AWEC analyses, the estimated cost of equity range resulting from AWEC's multi-stage DCF model would be as shown in Figure 12 below. As noted previously, since the filing of my direct testimony, the results of the DCF models have increased, however, even relying on the November 2023 data, the results of these models would support the Company's revised proposed ROE of 9.65 percent.

**Figure 12: Update to AWEC's Multi-Stage DCF Model- as of November 30, 2023**

| | Growth Rate Scenario | | |
|---|---|---|---|
| | Minimum | Average | Maximum |
| 30-day | 9.35% | 9.91% | 10.49% |
| 90-day | 9.29% | 9.84% | 10.41% |
| 180-day | 9.08% | 9.62% | 10.17% |
| Mean | 9.24% | 9.79% | 10.36% |

**Q. Have you updated this analysis to reflect more current market data?**

A. Yes. As shown in PAC/2218, I have updated the same analysis to rely on market data as of the end of June 2023, including the updated 30-year Treasury bond yield as the long-term growth rate. As shown in Figure 13 below, the results of the Multi-Stage DCF model, using AWEC witness Kaufman's prior specification, as presented in the

Sierra proceeding in May of this year have increased, demonstrating that the Company's revised ROE proposal of 9.65 percent is conservative.

**Figure 13:Update to AWEC Multi-Stage DCF Model- as of June 30, 2023**

| | Growth Rate Scenario | | |
|---|---|---|---|
| | Minimum | Average | Maximum |
| 30-day | 9.30% | 9.79% | 10.24% |
| 90-day | 9.46% | 9.97% | 10.42% |
| 180-day | 9.57% | 10.09% | 10.55% |
| Mean | 9.44% | 9.95% | 10.40% |

**Q. Have you considered the results of the Multi-Stage DCF using the range established by Staff's GDP growth rate estimates?**

A. Yes. As shown in Exhibit PAC/2218, relying on the low end of Staff's GDP growth rate estimates does not change the results in Figure 13 above significantly, since the GDP growth rate is only four basis points different than the yield on the 30-year Treasury bond. The results of that scenario range from 9.42 percent to 10.38 percent. The range of results using the high end of Staff's GDP growth rate estimates, of 5.10 percent, is 9.79 percent to 10.72 percent.

**Q. Do you agree with AWEC that Dr. Morin, the author or "New Regulatory Finance" advocates for the form of the Multi-Stage DCF model that AWEC has relied upon?**

A. No, I do not. While I agree with AWEC that Dr. Morin's works have been widely accepted texts on utility finance, I do not agree that Dr. Morin supports any form of the multi-stage DCF model. Further, it is my understanding of Dr. Morin's most recent work, that he does not support the fundamental assumption that utility growth should be limited to GDP in the long run.

It is also important to note that AWEC's source, *New Regulatory Finance* was published in 2006. Dr. Morin's more recent publication, *Modern Regulatory Finance* specifically addresses concerns with the fundamental assumptions relied upon by AWEC in the specification of the multi-stage DCF model. Specifically, Dr. Morin does not support the assumptions needed to develop either the two-stage or multi-stage DCF models.

> One central assumption in Multi-Stage DCF models, and a potential Achilles' heel, in my view, is that utility growth rates will eventually match the growth of the macroeconomy usually measured by the growth of the Gross Domestic Product (GDP). I am not aware of any financial literature supporting the notion that utility earnings per share are expected to grow at the average growth of the economy, or GDP.
>
> As discussed in Chapter 10, based upon the wealth of empirical and academic literature that supports the superiority of analyst's forecasts as a measure of investor expectations for the use of such forecasts in the DCF model, current earnings growth forecasts are the appropriate growth rates to use in a DCF analysis. Besides, to the extent that economic trends influence growth, it is reasonable to assume that they are already captured in analysts' growth estimates for utilities.
>
> Multi-stage DCF applications appear somewhat disconnected from the assumptions of the method and the consensus expectations of investors. The investment community does not look to GDP growth over the next several decades when evaluating an investment in utility stocks, nor does it anticipate a series of discrete muti-stage decennial stages. I am not aware of any evidence that investors evaluate the future based on the assumptions and data sources required to apply the two-stage or three-stage DCF model.[73]

**Q. What are your conclusions regarding AWEC's Multi-Stage DCF analyses?**

A. The following summarizes my conclusions regarding AWEC's Multi-stage DCF analyses.

[73] Roger Morin, *Modern Regulatory Finance*, p. 486.

- AWEC witness Kaufman has inexplicably changed the methodology for estimating the multi-stage DCF model from an approach that AWEC witness Kaufman relied upon only two months ago, using market data that was consistent with the data relied upon in AWEC's analyses in this proceeding. The effect of this change is to significantly understate the cost of equity resulting from AWEC's Multi-Stage DCF model.

- Updating AWEC's analysis to simply rely on the 30-year average Treasury yield as the GDP growth rate, which was one of the scenarios used in AWEC witness Kaufman's prior testimony results in a cost of equity range that demonstrates that the Company's revised proposed ROE is conservative and continues to support the initial request of 10.30 percent.

- Updating to current market data and relying on the range of GDP growth rates established by Staff demonstrates that the cost of equity has increased since the filing of my direct testimony and further demonstrates the reasonableness of the Company's initial proposed ROE, and their revised proposed ROE.

## B. Constant Growth DCF Analyses

**Q. How does AWEC develop their Constant Growth DCF analysis?**

A. AWEC conducts their constant growth DCF analyses using the same annualized dividends and 30-day, 90-day, and 180-day average stock prices of the proxy group companies as of November 30, 2023, as reflected in PAC/404 of my direct testimony, consistent with AWEC's multi-stage DCF analysis. AWEC assumes a growth rate for each proxy group company that is calculated as an average growth rate over a 30-year period that is based on (i) the average of analysts' projected EPS growth rates published by *Value Line*, *Yahoo! Finance*, and *Zacks* for years 1 through 5, (ii) a linear transition from the projected EPS growth rate to a "terminal" growth rate in years 6 through 24; and (iii) a "terminal" growth rate for years 25 through 30 that is based on the analyses previously discussed for AWEC's multi-stage DCF analysis.

**Q. Do you agree with AWEC's current specification of the Constant Growth DCF model?**

A. No. There are multiple problems with AWEC's constant growth DCF. I disagree with the following assumptions in AWEC's constant growth DCF model.

- AWEC witness Kaufman's unexplained departure from prior testimony on the use of EPS growth rates in the constant growth DCF model.
- The long-term average growth rate developed by AWEC based on the growth rate assumptions used in their multi-stage DCF analysis.
- AWEC's conclusion that the use of short-term growth rates in the constant-growth DCF model is contrary to investor expectations.

**Q. Please explain why you say that AWEC witness Kaufman's position with respect to the use of short-term earnings growth projections is inconsistent with AWEC witness Kaufman's prior testimony.**

A. Less than one year ago, AWEC witness Kaufman did not have the same concerns with the long-term growth rates used in the constant growth DCF model that is discussed in AWEC's testimony in this proceeding. At that time, AWEC witness Kaufman relied on projected EPS growth rates reported by *Value Line* to form the high end of the range of results, while the low end of the DCF results were based on AWEC witness Kaufman's own analysis of historical growth rates, using a Monte Carlo simulation to generate growth rates for the proxy group companies.[74]

[74] *In the Matter of Nevada Power Company d/b/a NV Energy, filed pursuant to NRS 704.100(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric customers,* Public Utilities Commission of Nevada, Docket Nos. 23-06007 and 23-06008, Prepared Direct Testimony of Lance D. Kaufman, Exhibit Kaufman-Direct-3, at 1-3 (Sept. 1, 2023).

**Q. Has AWEC witness Kaufman provided an explanation as to the changed methodology?**

A. No. As discussed in my review of AWEC's multi-stage DCF analysis, this change in methodology appears to be another example of AWEC witness Kaufman adjusting assumptions, where the change in assumptions has the effect of lowering the cost of equity estimates that result from Kaufman's analyses.

**Q. Do you agree with AWEC that the use of short-term earnings growth rates is unreasonable because there is no evidence that dividends can follow short-term earnings growth rates indefinitely?**

A. No, I do not. As discussed previously, Dr. Morin, whom AWEC accepts as having published the "widely adopted text on utility finance" outlines that there is no financial literature of which Dr. Morin is aware, that supports AWEC's view that utility earnings expected to grow at the average growth of the economy, or GDP.

**Q. What would the cost of equity range be if you relied on the constant growth DCF analysis from AWEC witness Kaufman's testimony in Nevada Public Utilities Commission Docket Nos. 23-06007 and 23-06008?**

A. As shown in Exhibit PAC/2218, I have calculated the "high end" scenario, developed by AWEC witness Kaufman in that proceeding, which is a constant growth DCF model using Value Line EPS growth rates. As shown in PAC/2218, the median range of results, using data as of November 30, 2023, were 9.78 percent to 10.13 percent. Updating the market data in that analysis through June 30, 2024, the median range is from 10.38 percent to 10.84 percent. The Company's initial proposed ROE of 10.30 percent and the revised proposal of 9.65 percent are supported by the

specification of the Constant Growth DCF model that AWEC witness Kaufman relied upon less than one year ago.[75]

**C. CAPM and ECAPM Analyses**

**Q. How does AWEC develop their CAPM AND ECAPM analyses?**

A. AWEC conducts four CAPM and ECAPM scenarios using the CAPM analyses that I developed in my direct testimony, relying on data as of November 30, 2023. AWEC states that they make two adjustments to the assumptions in my analysis 1) relying on raw betas and betas adjusted to the industry average rather than using the Blume adjustment that was relied upon in the published *Value Line* and *Bloomberg* Betas[76] that I have relied upon in my analysis and 2) adjusting the market risk premium calculation to include negative growth rates in the constant growth DCF analysis for the S&P 500 companies used in that analysis and to rely on the *Kroll* market risk premium.[77] The results of AWEC's CAPM analyses using the *Kroll* market risk premium are 7.94 percent to 8.28 percent. The results of AWEC's CAPM analyses using the projected DCF derived market risk premium, including negative growth rates, range from 9.40 percent to 9.88 percent.

AWEC uses the same assumptions to develop their ECAPM scenarios. The results of those scenarios are 8.33 percent to 8.58 percent using the Kroll market risk premium and 9.94 percent to 10.30 percent using the projected DCF-derived market risk premium.[78]

[75] The low-end scenario was based on a Monte Carlo simulation that is not sufficiently specified in AWEC witness Kaufman's testimony in that proceeding, and is unconventional, therefore I could not replicate that portion of analysis.
[76] AWEC/200, Kaufman/69.
[77] AWEC/200, Kaufman /82.
[78] AWEC/206, Kaufman/6.

**Q. As a threshold matter, are the resulting cost of equity estimates using the *Kroll* market risk premium reasonable?**

A. No. As noted previously, the CAPM results relying on this assumption are 7.94 percent to 8.28 percent and the ECAPM results are 8.33 percent to 8.58 percent. These results are well below any authorized ROE since 1980 in a jurisdiction with a comparable regulatory framework to Oregon. As such, it would be reasonable for the Commission to disregard the results of these CAPM analyses in establishing the ROE for the Company in this proceeding.

**Q. Does Staff rely on the betas that AWEC relies upon in their CAPM analysis?**

A. No. Both Staff and I rely on current *Value Line* betas in our CAPM analyses. In addition, I rely on Bloomberg betas and the long-term average *Value Line* beta.

**Q. Are the adjusted betas reported by Value Line and Bloomberg relied upon widely by investors?**

A. Yes. Both *Value Line* and *Bloomberg* have reported adjusted betas for decades, and it is clear that investors rely on these well-known and respected sources of financial data.

**Q. Is it reasonable to rely on industry or raw betas in the CAPM analysis?**

A. No. In reviewing the sources that AWEC has relied upon to support their testimony, the authors of those studies do not support their theories with respect to betas. For example, Dr. Morin, the author of <u>*New Regulatory Finance*</u>, which AWEC notes is a "widely adopted text on utility finance" specifically states the following:

> A comprehensive study of beta measurement methodology by Krysanowski and Jalilvand (1983) concludes that raw unadjusted beta (OLS beta) is one of the poorest beta predictors, and is outperformed by the Blume-style Baysian beta approach. Gombola

> and Kahl (1990) examine the time-series properties of utility betas and find strong support for the application of adjustment procedures such as Value Line and Bloomberg procedures.[79]

Further, Dr. Morin notes that the use of Blume adjusted betas is particularly relevant for utility stocks, that trade more like bonds.

> There is an additional economic justification for the use of adjusted betas in the case of regulated utilities. Adjusted betas compensate for the tendency of regulated utilities to be extra interest-sensitive relative to industrials. In the same way that bondholders get compensated for inflation through an inflation premium in the allowed rate of return. Thus, utility company returns are sensitive to interest rates. This is because the market index typically used in estimating betas is a stocks-only index, such as the S&P 500. A focus on stocks alone distorts the betas of regulated companies. The true risk of regulated utilities relative to other companies is understated because when interest rates change, the stocks of regulated companies react the same way as bonds do. A nominal interest rate on the face value of a bond offers the same pattern of future cash flows as a nominal return applied on the book value rate base. Empirical studies of utility returns confirm that betas are higher when calculated in the same way that captures interest rate sensitivity. The use of adjusted betas compensates for the interest sensitivity of regulated companies.[80]

Further, Michelfelder and Theodossiou specifically disagree with the use of raw betas in the CAPM.[81]

None of AWEC's beta coefficients (i.e., neither AWEC's raw betas nor the raw betas AWEC adjusts to an industry average raw beta) consider interest rate risk and likely understate the actual risk. Accordingly, AWEC's analysis understates the beta coefficients of the utility sector and in turn the results of their CAPM analyses using those betas. Conversely, the Blume adjustment applied by Value Line and

[79] Roger Morin, *Modern Regulatory Finance*. PUR Books, LLC, at 82 (2021).
[80] *Id.* Citing also to Myers, Kolbe, and Tye (1985) and Kolbe and Read (1984) for a full discussion of the sensitivity of utility stocks to interest rates including underlying theory and empirical evidence.
[81] R.A.Michelfelder & Theodossiou, *Public utility beta adjustment and biased costs of capital in public utility rate proceedings*, The Electricity Journal, 26(9), 60-68. P. (2013).

Bloomberg adjust the raw beta coefficients towards the market average of 1.0, thus likely better reflecting both the correlation with the broader market and the interest rate risk of the utility sector. Therefore, it is more appropriate to rely on the Value Line betas that have been used by Staff and myself or the adjusted Bloomberg betas that I have relied upon to specify the CAPM for the utilities sector.

**Q. Do you agree with AWEC that the use of Blume adjusted betas yield "unreasonable results"?[82]**

A. No, I do not. While AWEC quotes the details of Nobel Laureate William F. Sharpe's study on beta, AWEC apparently overlooked the fact that Sharpe, specifically noted that the differences between betas adjusted to the market to the industry adjustment should be minimal. Prior to Sharpe's derivation of a more precise predictive approach to estimating beta, Sharpe notes that the differences between the Blume adjustment and the industry adjustment should be insignificant:

> But what about simply investigating the extent to which a security's price moved with the market in the past? Such an approach ignores a myriad of possible differences between past and future. However, it is simple, and it does have some merit.
>
> As shown in Chapter 7, a security's beta value can be regarded as the slope of the characteristic line that best fits the relationship between its excess return and that of the market. If such a relationship were constant from period to period, one could estimate the value of beta for a stock by fitting a characteristic line to points representing the stock's excess return and the excess return on an index chosen to serve as a surrogate for the market portfolio. A simpler procedure would use only the period-by-period changes in the price of the stock and percentage changes in the level of the index. Happily for those who must calculate such numbers, the estimates obtained using the two procedures are very similar. One study showed that well over 99% of the differences in the estimated beta values of 1572 securities

[82] AWEC/200, Kaufman/75.

obtained via the complex procedure were associated with the differences among the estimates obtained in the simpler manner.[83]

**Q. Please summarize the literature you have referenced with respect to the use of Blume adjusted betas.**

A. I have reviewed three studies provided by AWEC that they suggest support their decision to rely on raw betas and industry adjusted betas. In total, these studies do not support the use of raw betas and suggest that the difference between industry adjust betas and market adjusted betas is insignificant. Further Sharpe's conclusions demonstrate that it is reasonable to expect that investors would rely on the simpler calculation (Blume adjustment) given the ease of calculation, the fact that they are readily published,[84] and the insignificant difference between the two calculations. This supports the use of Value Line betas that Staff and I relied upon and the Bloomberg adjusted betas used in my analyses.

**Q. Does AWEC witness Kaufman make changes to AWEC's CAPM methodology in this proceeding as compared with other recent testimony AWEC witness Kaufman has filed?**

A. Yes. This is the ***third model*** where AWEC witness Kaufman has substantially revised the assumptions relied upon with the end result of reducing the cost of equity range derived from AWEC witness Kaufman's analysis. In this case, AWEC witness Kaufman is supporting significantly different estimates of the market risk premium from the analyses AWEC Witness Kaufman relied upon in September 2023, filed in

[83] Investments, 2d ed., Prentice-Hall, Inc., Englewood Cliffs, 1981, p. 339.
[84] *Id.*, at 346.

Washington.[85] In that case, AWEC Witness Kaufman relied on my MRP as the "upper bound". In this case, AWEC modifies the upper bound by including negative growth rates in the constant growth DCF model used to set the MRP.

**Q. How does AWEC's change to the MRP calculation that AWEC Witness Kaufman accepted in the Washington proceeding affect the results of their CAPM analysis?**

A. Exhibit PAC/2220, demonstrates this change. The first portion of this exhibit simply reproduces AWEC's CAPM scenario using adjusted betas and their adjusted forward-looking market return. The second portion of this exhibit replaces AWEC's market return with the market return used in my direct testimony, which is consistent with the data AWEC used in the analyses in their testimony. As shown in this exhibit, the change that AWEC makes to the upper bound of the MRP in this proceeding has the effect of reducing the mean of AWEC's cost of equity estimates for the CAPM from 10.62 percent to 9.88 percent, a reduction of 74 basis points.

**Q. Do you agree with AWEC's criticism of your constant growth DCF estimate of the market return which is used to estimate the market risk premium?**

A. No. AWEC's proposed change to my constant growth DCF model violates the assumptions of the constant growth model and should be rejected on that basis. AWEC suggests that limiting the growth rates used in the DCF-derived market return calculation to between 0 and 20 percent is "arbitrary and clearly biased because they are not symmetric around zero". AWEC therefore suggests the use of growth rates

[85] *In the Matter of Alliance of Western Energy Consumers' Petition for Order Approving Deferral of Increased Fly Ash Revenues,* Washington Utilities and Transportation Commission, Docket UE-230172, Response Testimony of Lance D. Kaufman on behalf of Alliance of Western Energy Consumers, Sept. 14, 2023, at 22.

between -20 percent and 20 percent as reasonable to include in a constant growth DCF model. The fundamental problem with AWEC's assumption, however, is that it is unreasonable to rely on a negative growth rate in a constant growth DCF model, since no company can sustain negative growth in perpetuity. Therefore, AWEC's "correction" violates financial theory and should be rejected.

Further, AWEC is incorrect when they suggest that the methodology I relied upon to estimate the market return is arbitrary, as it is in fact commonly relied upon by the Federal Energy Regulatory Commission (FERC) in establishing the growth rates used for this purpose.[86]

**Q. Is the *Kroll* MRP that AWEC relies on in their other two CAPM scenarios consistent with the inverse relationship between interest rates and the MRP?**

A. No. Given the relatively low current yields on Treasury bonds as compared to those yields historically, and the inverse relationship between interest rates and the MRP, Staff's use of a risk-free rate that is below the historical average indicates that the MRP should be greater than the historical average MRP of 7.17 percent.[87] However, AWEC's MRP as reported by *Kroll* is significantly below the long-term historical average MRP also reported by *Kroll*. Consequently, the two CAPM scenarios in which Staff relies on this MRP are severely understated in the current market environment—and in fact, as previously discussed, produce a cost of equity that is

[86] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154 (2020), at p. 77.
[87] The market risk premium from 1926-2023 is calculated as the average return on the S&P 500 Index from 1926-2023 (12.04 percent) minus the average income-only return on long-term government bonds over the same time-period (4.87 percent). (Source: Kroll, Cost of Capital Navigator, 2023).

materially below any ROE authorized by a regulatory commission in the U.S. in at least 40 years in a jurisdiction with a comparable regulatory framework to Oregon.

**Q. Staff contends that your market return, and thus MRP, is abnormally high.[88] Is this accurate?**

A. No. First, as I previously discussed, both Staff's "adjusted" market return and their *Kroll* MRP are understated, which invalidates any comparison that they attempt to make using that data to suggest that either the market return or MRP in my CAPM analysis is overstated. Second, Staff's survey of market risk premium estimates, summarized in Table 13 of Staff's testimony, is a narrow sample of data that is skewed toward the low end of potential MRPs. Third, various regulatory commissions have supported the use of a constant growth DCF model to estimate the market return in the CAPM such as I have done.

**Q. Please summarize the results of the broader study on market risk premium estimates.**

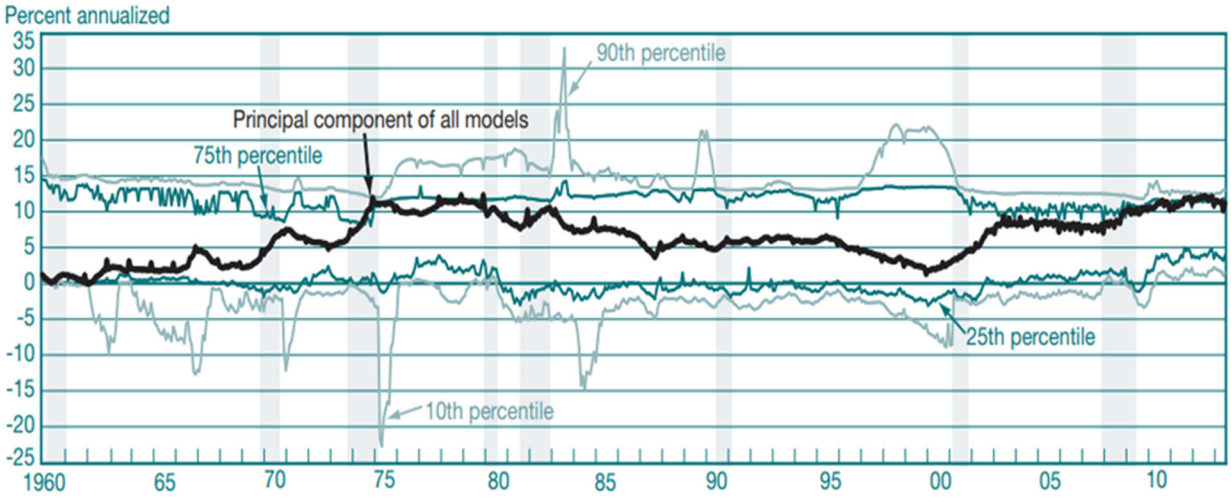
A. The Federal Reserve Bank of New York published an analysis in 2015 that reviewed 20 methodologies over the period 1960 through 2013 for estimating the MRP. The results of this study demonstrate that my MRP estimates, which are in the range of 7.78 percent to 8.46 percent, are reasonable. Specifically, the key conclusions from this study are:

- The 20 methodologies reviewed reflected a range for the MRP of between -1.0 percent to 14.5 percent.
- As shown in Figure 14, the principal component analysis of the 20 models (*i.e.*, the bold black line) produced a range for the MRP of approximately 0 percent to over 10 percent from 1960 through 2013.

[88] AWEC/200, Kaufman/69.

- The one-year-ahead MRP was consistently greater than 10 percent following the financial crisis of 2008/09.

**Figure 14: The Federal Reserve Bank of New York, One-Year-Ahead MRP[89]**




Further, the Federal Reserve Bank of New York also noted the following:

> Chart 2 shows the first principal component of all twenty models in black (the black line is the same principal component shown in black in each of the panels of Chart 1). As expected, the principal component tends to peak during financial turmoil, recessions, and periods of low real GDP growth or high inflation. It tends to bottom out after periods of sustained bullish stock markets and high real GDP growth. Evaluated by the first principal component, the one-year ahead ERP [equity risk premium] reaches a local peak in June 2012 at 12.2 percent. The surrounding months have ERP estimates of similar magnitude, with the most recent estimate in June 2013 at 11.2 percent. This behavior is not so clearly seen by simply looking at the collection of individual models in Chart 1, a finding that highlights the usefulness of principal component analysis. Similarly high levels were observed in the mid- and late 1970s, during a period of stagflation, while the recent financial crisis had slightly lower ERP estimates, closer to 10 percent.[90]

In summary, the Federal Reserve Bank of New York noted that the MRP is higher during periods of increased inflation. As discussed at length in my direct

[89] Fernando Duarte and Carla Rosa, *The Equity Risk Premium: A Review of Models*, Federal Reserve Bank of New York, 2015.
[90] *Id* (emphasis and clarification added).

testimony as well as herein, inflation remains well above the Federal Reserve's target of 2 percent and is expected to remain elevated over the near-term.

**Q. Please provide examples of other regulatory commissions that have relied on the calculation of the market risk premium that you have developed in your analysis.**

A. The following summarize several federal and state regulatory commissions that have relied on this calculation, demonstrating that there is no merit to AWEC's contention that my market return and MRP are unreasonable.

In Opinion No. 569-A, the FERC continued to support the use of the constant growth DCF model to calculate the market return for the CAPM, noting:

> We also continue to find that the CAPM should use a one-step DCF for its risk premium. This is because the rationale for using a two-step DCF methodology for a specific group of utilities does not apply when conducting a DCF study of the dividend-paying companies in the S&P 500, as the Commission found in Opinion Nos. 531-B and 569.172 A long-term component is unnecessary because of the regular updates to the S&P 500, which allows it to continue to grow at a short-term growth rate and because S&P 500 companies include stocks that are both new and mature, the latter of which have a moderating effect on the short-term growth rates.[91]

Likewise, various state utility regulatory commissions have also supported the use of a constant growth DCF model to estimate the market return in the CAPM. As shown in Figure 15, the Staff of the Illinois Commerce Commission (ICC), the Bureau of Investigation and Enforcement (I&E) of the Pennsylvania Public Utility Commission, and the Staff of the Maine Public Utilities Commission (Maine PUC)

[91] *Ass'n. of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154 (2020), p. 85. While this case has been remanded to the FERC, the issue addressed by the Supreme Court relates to FERC's justification of the use of the Risk Premium methodology in estimating the cost of equity and establishing the ROE, not the calculation of the market return in the CAPM. FERC's decision with respect to the calculation of the market return in the CAPM is not in question in the remand.

have each supported the forward-looking MRP, and the market return estimates using the constant growth DCF model. In each of these cases, the respective regulatory commission relied on the estimated CAPM results by these parties to determine the authorized ROE and did not dispute the use of the constant growth DCF model to calculate the market return.

**Figure 15: Examples of Jurisdictions Where the Market Return is Estimated Using the Constant Growth DCF Model**

| Intervening Party | Applicant | Docket No. | Approach of Intervening Party to Calculating the Market Return | Date of Order | Did the Commission Rely on the Intervening Party's CAPM? |
|---|---|---|---|---|---|
| Staff of the ICC | North Shore Gas Company | 20-0810 | CGDCF of the dividend-paying companies in the S&P 500 (11.95%)[92] | 9/8/21 | Yes[93] |
| I&E | Aqua Pennsylvania, Inc. | R-2021-3027385 | CGDCF of the *Value Line* Universe and S&P 500 (12.14%)[94] | 5/12/22 | Yes, the PA PUC placed primary weight on I&E's CAPM[95] |
| Staff of the Maine PUC | Northern Utilities, Inc. | 2019-00092 | CGDCF of the dividend-paying companies in the S&P 500 (11.33%-13.49%)[96] | 4/1/20 | Yes[97] |

**Q. What is AWEC's position regarding the ECAPM?**

A. AWEC witness Kaufman states the ECAPM has questionable assumptions that rely on dated statistical analysis, and it is not clear this relationship persists in this market today; therefore, no material weight should be placed on the results.[98]

[92] *In re North Shore Gas Company, Proposed increase in rates for gas distribution service,* Illinois Commerce Commission, Docket No. 20-0810, Order at 71 (Sept. 8, 2021).
[93] *Id*. at 86-87.
[94] *Penn. Pub. Service Comm., et al v. Aqua Pennsylvania Inc.,* Docket No. R-2021-3027385, Opinion and Order at 147 (May 16, 2022).
[95] *Id*. at 178.
[96] *Northern Utilities Inc. d/b/a UNITIL, Request for approval of rate change,* Maine Public Utilities Commission, Docket No. 2019-00092, Bench Analysis, at 21 (Oct. 29, 2019).
[97] *Id*., Order Part II at 58 (Apr. 1, 2020).
[98] AWEC/200, Kaufman/89.

**Q. Do you agree with AWEC's specification of the ECAPM?**

A. No. AWEC uses the same betas and market return or MRP from their CAPM analyses and, as I discussed, there are multiple problems with those assumptions.

**Q. Are you aware of academic studies that have used adjusted betas to estimate the ECAPM and which have shown the ECAPM has outperformed the traditional CAPM at predicting the applicable risk premium?**

A. Yes. For example, Chrétien and Coggins (2011) studied the CAPM and its ability to estimate the risk premium for the utility industry in particular subgroups of utilities for a data set that included market data through the end of 2006.[99] The authors considered the CAPM, the Fama-French three-factor model, and a model similar to the ECAPM. Their study shows that the ECAPM significantly outperformed the traditional CAPM at predicting the observed risk premium for the various utility subgroups, therefore addressing AWEC's concern regarding the performance of the ECAPM.

**Q. Are you aware of state regulatory commissions that have accepted the use of the ECAPM in the manner as you have conducted?**

A. Yes. There are various regulatory commissions that have supported the use of the ECAPM in establishing an authorized ROE and have done so when adjusted betas are used in the ECAPM analysis. For example, the New York Public Service Commission (NYPSC), the Montana Public Service Commission (Montana PSC), and North Carolina Utilities Commission (NCUC) have accepted the ECAPM analysis with the use of adjusted beta coefficients in establishing the authorized ROE

[99] Stéphane Chrétien and Frank Coggins, Cost of Equity for Energy Utilities: Beyond The CAPM, Energy Studies Review, Vol. 18, No. 2, 2011.

for regulated utilities. Specifically, the NYPSC gives equal weight to the CAPM and ECAPM (which it refers to as the "Zero Beta" CAPM) results,[100] the Montana PSC has expressed preference for the ECAPM analysis,[101] and the NCUC has recently found that both the adjustment to beta in the CAPM and the adjustment in the ECAPM were needed because they correct for different things.[102]

**Q. What is your conclusion regarding AWEC's CAPM and ECAPM results?**

A. I summarized literature from AWEC's own sources which suggest that the use of raw betas is not appropriate, and the use of industry betas should not be meaningfully different than the results of market-adjusted betas. Therefore, I do not believe it is appropriate to make these changes to my analysis. Further, I demonstrate that AWEC's adjustment to my market return, which was used to develop the MRP in my analysis violates the constant growth DCF model and therefore cannot be relied upon.

**D. Bond Yield Plus Risk Premium (BYRP)**

**Q. What is AWEC's position regarding the BYRP analysis?**

A. AWEC includes a summary paragraph at the outset of their testimony on the cost of capital suggesting that they disagree with the BYRP analysis, but they provide no further analytical support for these statements in the body of their testimony. As such,

[100] *Proceeding on Motion of the Comm'n as to Rates, Charges, Rules and Regulations of Corning Natural Gas Corporation for Gas Service,* New York Public Service Commission, Case No. 20-G-0101, Order at 44-46 (May 19, 2021).
[101] *In the Matter of the Joint Application for approval to change and establish natural gas delivery services rates for Energy West Montana, Inc. and Cut Bank Gas Co.,* Montana Public Service Commission, Docket No. D2017.9.80, Order No. 7575c at 46 (Sept. 26, 2018).
[102] *In the Matter of Application of Duke Energy Progress, LLC for adjustment of rates and charges applicable to electric service in North Carolina and performance based regulation,* North Carolina Utilities Commission, Docket No. E-2, SUB 1300, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice at 162-63 (Aug. 18, 2023).

the Commission cannot properly evaluate the merits of any of these statements and therefore they should be rejected.[103]

## E. Capital Structure

**Q. What has AWEC recommended regarding the appropriate capital structure for PacifiCorp?**

A. AWEC recommends that the Commission authorize the Company's projected capital structure, which is composed of 44.35 percent equity, 0.01 percent preferred stock and 44.99 percent debt.[104]

**Q. What are your concerns with AWEC's recommended capital structure?**

A. First, it appears that AWEC's proposal contains an error, as AWEC's proposed capitalization does not total to 100 percent. I assume that this is an error and that while they are proposing an equity ratio of 44.35 percent, the resulting debt percentage would be 55.64 percent. More importantly, AWEC's combined proposal is inconsistent with financial theory. Specifically, AWEC's proposal ignores the relationship between the capital structure and the cost of equity. While AWEC proposes a significant increase in the leverage in the Company's capital structure, and therefore the financial risk of the Company, AWEC makes no adjustment to the ROE to reflect the incremental risk they propose to impose on equity investors. Further, AWEC testifies that it is appropriate to assign asymmetrical risk in the treatment of a hypothetical capital structure; requiring the Company to assume a hypothetical capital structure to lower its equity ratio when the actual equity ratios are high but not to increase the equity ratio when it is excessively low. This proposal lacks credibility

[103] AWEC/200, Kaufman/64.
[104] AWEC/200, Kaufman/50.

and is inconsistent with a fair and reasonable return which is one of the fundamental principles of regulation.

**Q. Does AWEC establish any benchmarks to determine an "excessively high" or "excessively low" equity ratio?**

A. No. While I disagree with Staff's calculation of the Hamada adjustment, Staff and I both recognize the financial risk related to capitalization and the need to consider the capital structures of the proxy group companies in estimating the appropriate ROE for the Company, however AWEC does not address this risk in their testimony nor do they consider their proposal relative to the financial risk that is reflected in the market data for the proxy group companies.

**Q. Have you conducted that analysis?**

A. Yes. As discussed in my direct testimony, and shown in PAC/416, I evaluated the capital structures of the proxy companies used in my direct testimony. Since AWEC uses my analysis and proxy group as the foundation for their testimony, the capitalization presented in this exhibit is appropriate to consider in the context of their overall recommended ROE. As shown in that exhibit, the average equity ratio of the proxy group companies is 52.89 percent, which is ***854 basis points higher*** than the equity ratio proposed by AWEC. Failure to address this difference in financial risk is a fundamental flaw in AWEC's overall recommendations.

**Q. Have you evaluated the effect of the incremental financial risk proposed by AWEC to the cost of equity that would be required at AWEC's proposed equity ratio of 44.35 percent?**

A. Yes. As an illustrative example, as shown in Exhibit PAC/2221, I have applied the Hamada adjustment, as Staff has done,[105] using AWEC's proposed debt ratio of 55.64 percent. As shown in that exhibit, the appropriate adjustment to the ROE for AWEC's proposed capitalization would be an increase of approximately 100 basis points, which would result in an ROE recommendation of 10.25 percent, using AWEC's ROE analyses, as filed. As noted previously, I have demonstrated that the assumptions in those analyses have been modified as compared with AWEC's prior testimony in other recent cases, resulting in cost of equity estimates that are artificially reduced. Taking these factors into consideration demonstrates that the Company's revised proposed ROE is conservative.

**F. Conclusions**

**Q. Please summarize your conclusions regarding AWEC's analyses in this proceeding.**

A. I demonstrate that the assumptions and methodologies used in AWEC witness Kaufman's analysis in this proceeding are significantly different than the assumptions AWEC witness Kaufman relied upon in recent cases over the past year, and in some cases, the last two months. AWEC has provided no reason for why AWEC witness Kaufman has made such significant changes in the approach to estimating the cost of equity. I have demonstrated that relying on the prior assumptions and analyses that

[105] The Hamada adjustment applied in PAC/2221 is adjusted to correct for the issues I raise in response to Staff.

AWEC witness Kaufman used over this 12- month period would have resulted in significantly higher estimates of the cost of equity than the estimates AWEC witness Kaufman has derived using new assumptions in this proceeding. Finally, I have summarized the results of the methodologies that AWEC used to find appropriate to estimate the cost of equity in Figure 16 below and Exhibit PAC/2217. These results support the Company's initial proposed ROE of 10.30 percent and the demonstrate that the Company's revised proposed ROE of 9.65 percent is conservative.

Regarding AWEC's capital structure recommendation, I disagree with their proposal to apply asymmetrical ratemaking principals that, in this proceeding, serve to weaken the Company's financial metrics in this proceeding and at a time when the Company needs access to capital to meet its aggressive capital investment plan.

**Figure 16: Summary of cost of equity estimates using Kaufman's prior estimation methodologies[106]**

| *Constant Growth DCF* | | |
|---|---|---|
| | **As Filed [1]** | |
| | 11/30/2023 | |
| | Mean | Median |
| 30-day | 9.24% | 9.27% |
| 90-day | 9.18% | 9.09% |
| 180-day | 8.99% | 8.96% |

| *Multi Stage DCF* | | |
|---|---|---|
| | **As Filed [1]** | |
| | 11/30/2023 | |
| | Mean | Median |
| 30-day | 9.45% | 9.48% |
| 90-day | 9.38% | 9.30% |
| 180-day | 9.15% | 9.16% |

| *CAPM/ECAPM (Upper bound)* | | |
|---|---|---|
| | **As Filed [1]** | |
| | 11/30/2023 | |
| | Mean | Median |
| CAPM | 9.88% | 9.85% |
| ECAPM | 10.30% | 10.29% |

| **EPS Growth Rates from Value Line [2]** | | |
|---|---|---|
| | 11/30/2023 | |
| | Mean | Median |
| 30-day | 10.03% | 10.13% |
| 90-day | 9.97% | 10.12% |
| 180-day | 9.78% | 10.01% |

| **Long-term growth = Average T-Bond [2]** | | |
|---|---|---|
| | 11/30/2023 | |
| | Mean | Median |
| 30-day | 9.91% | 9.94% |
| 90-day | 9.84% | 9.76% |
| 180-day | 9.62% | 9.63% |

| **Bulkley Market Return Calculation [2]** | | |
|---|---|---|
| | 11/30/2023 | |
| | Mean | Median |
| CAPM | 10.62% | 10.59% |
| ECAPM | 11.10% | 11.08% |

| **Decrease Resulting from Change in Methodology** | | |
|---|---|---|
| | Mean | Median |
| 30-day | -0.79% | -0.86% |
| 90-day | -0.79% | -1.03% |
| 180-day | -0.79% | -1.05% |

| **Decrease Resulting from Change in Methodology** | | |
|---|---|---|
| | Mean | Median |
| 30-day | -0.46% | -0.45% |
| 90-day | -0.46% | -0.46% |
| 180-day | -0.47% | -0.47% |

| **Decrease Resulting from Change in Methodology** | | |
|---|---|---|
| | Mean | Median |
| CAPM | -0.74% | -0.74% |
| ECAPM | -0.80% | -0.80% |

| **Update Data using UE-230172 Methodology** | | |
|---|---|---|
| | 6/30/2024 | |
| | Mean | Median |
| | 10.15% | 10.58% |
| | 10.09% | 10.58% |
| | 9.89% | 10.30% |

| **Long-term growth = Average T-Bond [2]** | | |
|---|---|---|
| | 6/30/2024 | |
| | Mean | Median |
| | 9.79% | 9.53% |
| | 9.97% | 9.79% |
| | 10.09% | 9.99% |

## VII. RESPONSE TO WALMART WITNESS WALMART

**Q. Please summarize the ROE testimony of Walmart.**

A. Walmart does not conduct an ROE analysis and does not provide a specific ROE recommendation for PacifiCorp in this proceeding. Rather, Walmart recommends that the Commission closely examine the Company's proposed ROE in light of (1) the Company's currently authorized ROE; and (2) authorized ROEs in Texas and other jurisdictions nationally since 2021.[107]

[106] CAPM/ECAPM not updated to reflect industry betas.
[107] Walmart/100, Austin/5.

**Q. What is your response to the data that Walmart has provided for the Commission's consideration regarding ROEs that have been authorized since 2021?**

A. Walmart's analysis of authorized ROEs suffers from several flaws, one of which is that the data for the time period that they have evaluated cannot be relied upon in setting the ROE in current market conditions, due to the significant change in interest rates since 2021. However, as shown on Exhibit Walmart/104, the Company's revised requested ROE of 9.65 percent is generally consistent with the national average authorized ROE for vertically integrated electric utilities, since 2021 of 9.62 percent. Further, as shown on Exhibit Walmart/102, while authorized ROEs have increased since 2021, the Company's revised request is lower than the average authorized ROE in 2023 and 2024.

**Q. Do you agree with Walmart's review of authorized ROEs since 2021 as a basis for comparison to the Company's current cost of equity?**

A. No. As mentioned previously, Walmart's review of authorized ROEs since 2021 fails to consider that market conditions have changed dramatically over this period. As discussed previously herein, since the Company's last rate case, the following significant changes have occurred to macroeconomic indicators that affect the cost of equity:

- The federal funds rate has increased approximately 300 basis points.
- The yield on the 30-year Treasury bond has increased approximately 135 basis points.
- While core inflation has declined significantly, it remains well above the FOMC target level of 2.00 percent.

These factors demonstrate that directionally, the cost of equity has increased. As shown in Exhibit PAC/2208, the long-term relationship between authorized ROEs and Treasury bond yields demonstrates that as interest rates increase, the authorized ROE has increased by approximately 58 percent. This historical relationship generally supports the expectation that ROEs would increase as interest rates increase.

**Q. How do current macroeconomic indicators compare to the market conditions at the time of the Commission's decisions in the other Oregon cases that Walmart has summarized?**

A. First, it is important to note that all of the recent cases cited by Walmart that were concluded by this Commission were settlements. While the Commission approved the settlements, the Commission did not expressly determine the ROE in those proceedings. Therefore, since settlements represent the totality of the discussions and often concessions made by each of the parties, it is not appropriate to suggest that the Commission determined the ROEs in these proceedings based on the market-required return on equity.

**Q. Does Walmart's analysis rely only on cases that are comparable to PacifiCorp?**

A. No. Walmart does not remove formula rate plans from their analysis. Specifically, Walmart's analysis includes authorized ROEs for Green Mountain Power which are set pursuant to a formula rate. While I disagree with the use of data from 2021 forward, simply excluding the Green Mountain Power cases from the analysis performed by Walmart increases the average authorized ROEs for vertically

integrated electric utilities since 2021 to 9.65 percent, which is consistent with the Company's revised request.

**Q. Why should formula rates be excluded from an analysis of authorized ROEs?**

A. ROEs that are established pursuant to a formula should be excluded from an analysis that is comparing authorized ROEs to market-based analyses because these regulatory constructs are inconsistent with the form of regulation relied upon by this Commission in setting the Company's authorized ROE. In particular, the Vermont formula rate proceedings reflect annual revenue requirement changes that included all capital investment incurred in the prior year, rather than the traditional ratemaking structure employed in Oregon. Therefore, returns established under these formula rate plans are not comparable to Oregon regulation and should not be considered in setting the ROE for PacifiCorp.

**Q. Should Walmart have also evaluated the authorized capitalization in the analysis that she presented regarding national trends in authorized ROEs?**

A. Yes. Capitalization affects the overall financial risk of the company. To the extent that a company has greater leverage, there is increased risk to equity, since equity holders are the last claimants in the event of the dissolution of the company. Further, creditors and credit rating agencies also consider the overall leverage in their determination of the overall risk profile of a company. Credit rating agencies use various funds from operations-to-debt metrics, which are affected by the overall capitalization of the company, in establishing their credit ratings. An analysis that considers only the ROE without consideration of the differences in financial risk, is flawed and cannot be relied upon to determine an appropriate ROE. This is of

particular importance in this proceeding, where there is a significant difference between the Company's equity ratio and the average equity ratio of the proxy group entities.

**Q. Have you conducted such an analysis?**

A. Yes. As shown in Exhibit PAC/416 to my direct testimony, the utility operating companies of the proxy group companies have an equity ratio on average of approximately 52.42 percent, which means that, given the Company's proposed equity ratio of 50.00 percent, the Company would have greater leverage than the proxy group on average, which results in greater financial risk.

**Q. Has Walmart reviewed the capitalization of the companies in their national authorized ROE analysis?**

A. Yes. While Walmart does not suggest that the Commission consider this information, as shown in Exhibit Walmart/102, Walmart provides the average equity ratios for the same group of companies that they include in their review of authorized ROEs. As shown in that exhibit, relying on the same time-period used by Walmart for their ROE comparison, the average authorized equity ratio for vertically integrated electric utilities was 50.94 percent, which is higher than the Company's proposed equity ratio. This analysis demonstrates that the Company's capital structure, if approved as requested, represents greater financial risk than the capital structures that have been authorized for distribution electric utilities in other regulatory jurisdictions across the country.

**Q. What are your conclusions regarding Walmart's analysis and their recommendation to the Commission?**

A. Walmart has not conducted a market-based, risk-comparable analysis of the investor required ROE in the current market environment for an investment in PacifiCorp. Therefore, their recommendations to the Commission lack the analytical rigor necessary to inform their decision on the appropriate ROE for the Company. However, if the Commission were to consider the results of Walmart's limited analysis, even without correcting for the flaws discussed, the average authorized ROE from 2021 through 2024 supports the Company's revised requested ROE of 9.65 percent.

## VIII. RESPONSE TO CUB

**Q. Please summarize CUB's testimony with respect to the Commission authorized return on equity.**

A. CUB proposes that the Commission manage the Company's revenue requirement and any potential rate shock by setting the ROE at the lowest level of a reasonable range.[108]

**Q. Is CUB's proposal consistent with the regulatory principles established by the U.S. Supreme Court and the principles that have been relied upon by this Commission?**

A. No. CUB's proposal is inconsistent with traditional utility ratemaking and the precedent established by the U.S. Supreme Court and the Commission. As noted in

[108] CUB/100, Jenks/16-17.

my direct testimony, the U.S. Supreme Court's *Hope* and *Bluefield* decisions[109] established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates. This standard establishes that the return that should be authorized for investors in regulated utilities should be based on the risk of the investment.

**Q. Has the Commission established guidelines that are similar to the precedent established in Hope and Bluefield?**

A. Yes. As discussed in my direct testimony, in the Company's 2020 general rate case, the Commission established the following:

> In establishing fair and reasonable rates under ORS 756.040, we balance the interests of the utility investor and customers by ensuring that the rates provide adequate revenue both for operating expenses and for capital costs of the utility, with a return to the equity holder that is "commensurate with the return on investments in other enterprises having corresponding risks" and "sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[110]

Based on these standards, the authorized ROE should provide the Company with a fair and reasonable return and should provide access to capital on reasonable terms in a variety of market conditions and should not be arbitrarily adjusted to address other policy objectives.

[109] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944) (Hope); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia,* 262 U.S. 679 (1923) (Bluefield).
[110] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision,* Docket No. UE 374, Order No. 20-473 at 6 (Dec. 18, 2020).

**Q. Does this conclude your reply testimony?**

A. Yes, it does.

Docket No. UE 433
Exhibit PAC/2201
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Summary of Updated Cost of Equity Results**

**July 2024**

**COST OF EQUITY ANALYSES**
**SUMMARY OF RESULTS**

***Constant Growth DCF***

| | Minimum Growth Rate | Average Growth Rate | Maximum Growth Rate |
|---|---|---|---|
| Mean Results: | | | |
| 30-Day Avg. Stock Price | 9.49% | 10.57% | 11.42% |
| 90-Day Avg. Stock Price | 9.63% | 10.71% | 11.56% |
| 180-Day Avg. Stock Price | 9.72% | 10.80% | 11.66% |
| Average | 9.62% | 10.69% | 11.55% |
| Median Results: | | | |
| 30-Day Avg. Stock Price | 9.85% | 10.48% | 11.15% |
| 90-Day Avg. Stock Price | 9.98% | 10.65% | 11.31% |
| 180-Day Avg. Stock Price | 10.03% | 10.76% | 11.42% |
| Average | 9.95% | 10.63% | 11.29% |

***Multi-Stage DCF***

| | Minimum Growth Rate | Average Growth Rate | Maximum Growth Rate |
|---|---|---|---|
| Mean Results: | | | |
| 30-Day Avg. Stock Price | 9.88% | 10.16% | 10.40% |
| 90-Day Avg. Stock Price | 10.03% | 10.31% | 10.57% |
| 180-Day Avg. Stock Price | 10.13% | 10.42% | 10.68% |
| Average | 10.01% | 10.30% | 10.55% |
| Median Results: | | | |
| 30-Day Avg. Stock Price | 9.79% | 9.94% | 10.18% |
| 90-Day Avg. Stock Price | 10.02% | 10.13% | 10.31% |
| 180-Day Avg. Stock Price | 10.10% | 10.28% | 10.47% |
| Average | 9.97% | 10.12% | 10.32% |

***CAPM / ECAPM / Bond Yield Risk Premium***

| | 30-Year Treasury Bond Yield | | |
|---|---|---|---|
| | Current 30-Day Avg | Near-Term Projected | Longer-Term Projected |
| CAPM: | | | |
| Current *Value Line* Beta | 12.07% | 12.06% | 12.05% |
| Current Bloomberg Beta | 10.90% | 10.86% | 10.85% |
| Long-term Avg. *Value Line* Beta | 10.69% | 10.65% | 10.64% |
| ECAPM: | | | |
| Current *Value Line* Beta | 12.22% | 12.21% | 12.20% |
| Current Bloomberg Beta | 11.34% | 11.31% | 11.30% |
| Long-term Avg. *Value Line* Beta | 11.18% | 11.15% | 11.15% |
| Bond Yield Risk Premium | 10.62% | 10.52% | 10.51% |

Docket No. UE 433
Exhibit PAC/2202
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Constant Growth Discounted Cash Flow Model**

**July 2024**

**30-DAY CONSTANT GROWTH DCF**

| Company | | [1] Annualized Dividend | [2] Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Value Line Projected EPS Growth Rate | [6] Yahoo! Finance Projected EPS Growth Rate | [7] Zacks Projected EPS Growth Rate | [8] Average Projected EPS Growth Rate | [9] Cost of Equity: Minimum Growth Rate | [10] Cost of Equity: Mean Growth Rate | [11] Cost of Equity: Maximum Growth Rate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Alliant Energy Corporation | LNT | $1.92 | $50.66 | 3.79% | 3.91% | 6.00% | 6.30% | 6.10% | 6.13% | 9.90% | 10.04% | 10.21% |
| Ameren Corporation | AEE | $2.68 | $71.34 | 3.76% | 3.87% | 6.50% | 5.50% | 6.20% | 6.07% | 9.36% | 9.94% | 10.38% |
| American Electric Power Company, Inc | AEP | $3.52 | $89.01 | 3.95% | 4.08% | 6.50% | 6.36% | 6.10% | 6.32% | 10.18% | 10.40% | 10.58% |
| Avista Corporation | AVA | $1.90 | $35.62 | 5.33% | 5.50% | 6.00% | 6.20% | n/a | 6.10% | 11.49% | 11.60% | 11.70% |
| CMS Energy Corporation | CMS | $2.06 | $60.92 | 3.38% | 3.50% | 5.00% | 7.60% | 7.60% | 6.73% | 8.47% | 10.23% | 11.11% |
| Duke Energy Corporation | DUK | $4.10 | $101.95 | 4.02% | 4.14% | 5.00% | 6.66% | 6.10% | 5.92% | 9.12% | 10.06% | 10.82% |
| Entergy Corporation | ETR | $4.52 | $108.95 | 4.15% | 4.25% | 0.50% | 6.80% | 7.30% | 4.87% | 4.66% | 9.12% | 11.60% |
| Evergy, Inc. | EVRG | $2.57 | $53.56 | 4.80% | 4.95% | 7.50% | 6.00% | 5.00% | 6.17% | 9.92% | 11.11% | 12.48% |
| IDACORP, Inc. | IDA | $3.32 | $93.69 | 3.54% | 3.63% | 5.00% | 4.40% | n/a | 4.70% | 8.02% | 8.33% | 8.63% |
| NextEra Energy, Inc. | NEE | $2.06 | $74.85 | 2.75% | 2.87% | 8.00% | 8.20% | 8.60% | 8.27% | 10.86% | 11.13% | 11.47% |
| NorthWestern Corporation | NWE | $2.60 | $50.34 | 5.16% | 5.27% | 4.00% | 4.50% | n/a | 4.25% | 9.27% | 9.52% | 9.78% |
| OGE Energy Corporation | OGE | $1.67 | $35.77 | 4.68% | 4.81% | 6.50% | negative | 5.00% | 5.75% | 9.79% | 10.56% | 11.33% |
| Pinnacle West Capital Corporation | PNW | $3.52 | $76.61 | 4.59% | 4.75% | 4.50% | 7.20% | 8.20% | 6.63% | 9.20% | 11.38% | 12.98% |
| Portland General Electric Company | POR | $2.00 | $43.02 | 4.65% | 4.86% | 6.00% | 12.50% | n/a | 9.25% | 10.79% | 14.11% | 17.44% |
| Southern Company | SO | $2.88 | $78.61 | 3.66% | 3.79% | 6.50% | 7.30% | 7.00% | 6.93% | 10.28% | 10.72% | 11.10% |
| Xcel Energy Inc. | XEL | $2.19 | $54.15 | 4.04% | 4.18% | 7.00% | 6.73% | 6.40% | 6.71% | 10.57% | 10.89% | 11.19% |
| Mean | | | | | | | | | | 9.49% | 10.57% | 11.42% |
| Median | | | | | | | | | | 9.85% | 10.48% | 11.15% |

Notes:
[1] Bloomberg Professional as of June 30, 2024
[2] Bloomberg Professional 30-day average as of June 30, 2024
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

**90-DAY CONSTANT GROWTH DCF**

| Company | | [1] Annualized Dividend | [2] Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Value Line Projected EPS Growth Rate | [6] Yahoo! Finance Projected EPS Growth Rate | [7] Zacks Projected EPS Growth Rate | [8] Average Projected EPS Growth Rate | [9] Cost of Equity: Minimum Growth Rate | [10] Cost of Equity: Mean Growth Rate | [11] Cost of Equity: Maximum Growth Rate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Alliant Energy Corporation | LNT | $1.92 | $49.53 | 3.88% | 4.00% | 6.00% | 6.30% | 6.10% | 6.13% | 9.99% | 10.13% | 10.30% |
| Ameren Corporation | AEE | $2.68 | $71.82 | 3.73% | 3.84% | 6.50% | 5.50% | 6.20% | 6.07% | 9.33% | 9.91% | 10.35% |
| American Electric Power Company, Inc | AEP | $3.52 | $85.75 | 4.11% | 4.23% | 6.50% | 6.36% | 6.10% | 6.32% | 10.33% | 10.55% | 10.74% |
| Avista Corporation | AVA | $1.90 | $34.85 | 5.45% | 5.62% | 6.00% | 6.20% | n/a | 6.10% | 11.61% | 11.72% | 11.82% |
| CMS Energy Corporation | CMS | $2.06 | $59.65 | 3.45% | 3.57% | 5.00% | 7.60% | 7.60% | 6.73% | 8.54% | 10.30% | 11.18% |
| Duke Energy Corporation | DUK | $4.10 | $97.53 | 4.20% | 4.33% | 5.00% | 6.66% | 6.10% | 5.92% | 9.31% | 10.25% | 11.00% |
| Entergy Corporation | ETR | $4.52 | $105.61 | 4.28% | 4.38% | 0.50% | 6.80% | 7.30% | 4.87% | 4.79% | 9.25% | 11.74% |
| Evergy, Inc. | EVRG | $2.57 | $52.07 | 4.94% | 5.09% | 7.50% | 6.00% | 5.00% | 6.17% | 10.06% | 11.25% | 12.62% |
| IDACORP, Inc. | IDA | $3.32 | $92.22 | 3.60% | 3.68% | 5.00% | 4.40% | n/a | 4.70% | 8.08% | 8.38% | 8.69% |
| NextEra Energy, Inc. | NEE | $2.06 | $66.86 | 3.08% | 3.21% | 8.00% | 8.20% | 8.60% | 8.27% | 11.20% | 11.47% | 11.81% |
| NorthWestern Corporation | NWE | $2.60 | $49.38 | 5.27% | 5.38% | 4.00% | 4.50% | n/a | 4.25% | 9.37% | 9.63% | 9.88% |
| OGE Energy Corporation | OGE | $1.67 | $34.52 | 4.85% | 4.99% | 6.50% | negative | 5.00% | 5.75% | 9.97% | 10.74% | 11.50% |
| Pinnacle West Capital Corporation | PNW | $3.52 | $73.66 | 4.78% | 4.94% | 4.50% | 7.20% | 8.20% | 6.63% | 9.39% | 11.57% | 13.17% |
| Portland General Electric Company | POR | $2.00 | $41.88 | 4.78% | 5.00% | 6.00% | 12.50% | n/a | 9.25% | 10.92% | 14.25% | 17.57% |
| Southern Company | SO | $2.88 | $73.26 | 3.93% | 4.07% | 6.50% | 7.30% | 7.00% | 6.93% | 10.56% | 11.00% | 11.37% |
| Xcel Energy Inc. | XEL | $2.19 | $53.46 | 4.10% | 4.23% | 7.00% | 6.73% | 6.40% | 6.71% | 10.63% | 10.94% | 11.24% |
| Mean | | | | | | | | | | 9.63% | 10.71% | 11.56% |
| Median | | | | | | | | | | 9.98% | 10.65% | 11.31% |

Notes:
[1] Bloomberg Professional as of June 30, 2024
[2] Bloomberg Professional 90-day average as of June 30, 2024
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

**180-DAY CONSTANT GROWTH DCF**

| Company | | [1] Annualized Dividend | [2] Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Value Line Projected EPS Growth Rate | [6] Yahoo! Finance Projected EPS Growth Rate | [7] Zacks Projected EPS Growth Rate | [8] Average Projected EPS Growth Rate | [9] Cost of Equity: Minimum Growth Rate | [10] Cost of Equity: Mean Growth Rate | [11] Cost of Equity: Maximum Growth Rate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Alliant Energy Corporation | LNT | $1.92 | $49.21 | 3.90% | 4.02% | 6.00% | 6.30% | 6.10% | 6.13% | 10.02% | 10.15% | 10.32% |
| Ameren Corporation | AEE | $2.68 | $72.14 | 3.71% | 3.83% | 6.50% | 5.50% | 6.20% | 6.07% | 9.32% | 9.89% | 10.34% |
| American Electric Power Company, Inc | AEP | $3.52 | $81.37 | 4.33% | 4.46% | 6.50% | 6.36% | 6.10% | 6.32% | 10.56% | 10.78% | 10.97% |
| Avista Corporation | AVA | $1.90 | $34.01 | 5.59% | 5.76% | 6.00% | 6.20% | n/a | 6.10% | 11.75% | 11.86% | 11.96% |
| CMS Energy Corporation | CMS | $2.06 | $57.67 | 3.57% | 3.69% | 5.00% | 7.60% | 7.60% | 6.73% | 8.66% | 10.43% | 11.31% |
| Duke Energy Corporation | DUK | $4.10 | $94.20 | 4.35% | 4.48% | 5.00% | 6.66% | 6.10% | 5.92% | 9.46% | 10.40% | 11.16% |
| Entergy Corporation | ETR | $4.52 | $101.22 | 4.47% | 4.57% | 0.50% | 6.80% | 7.30% | 4.87% | 4.98% | 9.44% | 11.93% |
| Evergy, Inc. | EVRG | $2.57 | $50.70 | 5.07% | 5.23% | 7.50% | 6.00% | 5.00% | 6.17% | 10.20% | 11.39% | 12.76% |
| IDACORP, Inc. | IDA | $3.32 | $93.06 | 3.57% | 3.65% | 5.00% | 4.40% | n/a | 4.70% | 8.05% | 8.35% | 8.66% |
| NextEra Energy, Inc. | NEE | $2.06 | $61.96 | 3.32% | 3.46% | 8.00% | 8.20% | 8.60% | 8.27% | 11.46% | 11.73% | 12.07% |
| NorthWestern Corporation | NWE | $2.60 | $48.68 | 5.34% | 5.45% | 4.00% | 4.50% | n/a | 4.25% | 9.45% | 9.70% | 9.96% |
| OGE Energy Corporation | OGE | $1.67 | $34.06 | 4.91% | 5.05% | 6.50% | negative | 5.00% | 5.75% | 10.03% | 10.80% | 11.57% |
| Pinnacle West Capital Corporation | PNW | $3.52 | $72.08 | 4.88% | 5.05% | 4.50% | 7.20% | 8.20% | 6.63% | 9.49% | 11.68% | 13.28% |
| Portland General Electric Company | POR | $2.00 | $41.10 | 4.87% | 5.09% | 6.00% | 12.50% | n/a | 9.25% | 11.01% | 14.34% | 17.67% |
| Southern Company | SO | $2.88 | $70.45 | 4.09% | 4.23% | 6.50% | 7.30% | 7.00% | 6.93% | 10.72% | 11.16% | 11.54% |
| Xcel Energy Inc. | XEL | $2.19 | $56.13 | 3.90% | 4.03% | 7.00% | 6.73% | 6.40% | 6.71% | 10.43% | 10.74% | 11.04% |
| Mean | | | | | | | | | | 9.72% | 10.80% | 11.66% |
| Median | | | | | | | | | | 10.03% | 10.76% | 11.42% |

Notes:
[1] Bloomberg Professional as of June 30, 2024
[2] Bloomberg Professional 180-day average as of June 30, 2024
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

Docket No. UE 433
Exhibit PAC/2203
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Multi-Stage Discounted Cash Flow Model**

**July 2024**

**MULTI-STAGE DCF**

**MINIMUM FIRST STAGE GROWTH RATE**
**STOCK PRICE AVERAGING CONVENTION: 30 DAYS**

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Company | | Annualized Dividend | Stock Price | First Stage Gwth Rate | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Third Stage Growth Rate | ROE |
| Alliant Energy Corporation | LNT | $1.92 | $50.66 | 6.00% | 5.92% | 5.83% | 5.75% | 5.66% | 5.58% | 5.49% | 9.68% |
| Ameren Corporation | AEE | $2.68 | $71.34 | 5.50% | 5.50% | 5.50% | 5.50% | 5.50% | 5.50% | 5.49% | 9.52% |
| American Electric Power Company, Inc. | AEP | $3.52 | $89.01 | 6.10% | 6.00% | 5.90% | 5.80% | 5.70% | 5.60% | 5.49% | 9.89% |
| Avista Corporation | AVA | $1.90 | $35.62 | 6.00% | 5.92% | 5.83% | 5.75% | 5.66% | 5.58% | 5.49% | 11.43% |
| CMS Energy Corporation | CMS | $2.06 | $60.92 | 5.00% | 5.08% | 5.16% | 5.25% | 5.33% | 5.41% | 5.49% | 9.00% |
| Duke Energy Corporation | DUK | $4.10 | $101.95 | 5.00% | 5.08% | 5.16% | 5.25% | 5.33% | 5.41% | 5.49% | 9.69% |
| Entergy Corporation | ETR | $4.52 | $108.95 | 0.50% | 1.33% | 2.16% | 3.00% | 3.83% | 4.66% | 5.49% | 8.77% |
| Evergy, Inc. | EVRG | $2.57 | $53.56 | 5.00% | 5.08% | 5.16% | 5.25% | 5.33% | 5.41% | 5.49% | 10.53% |
| IDACORP, Inc. | IDA | $3.32 | $93.69 | 4.40% | 4.58% | 4.76% | 4.95% | 5.13% | 5.31% | 5.49% | 9.05% |
| NextEra Energy, Inc. | NEE | $2.06 | $74.85 | 8.00% | 7.58% | 7.16% | 6.75% | 6.33% | 5.91% | 5.49% | 8.90% |
| NorthWestern Corporation | NWE | $2.60 | $50.34 | 4.00% | 4.25% | 4.50% | 4.75% | 5.00% | 5.25% | 5.49% | 10.62% |
| OGE Energy Corporation | OGE | $1.67 | $35.77 | 5.00% | 5.08% | 5.16% | 5.25% | 5.33% | 5.41% | 5.49% | 10.39% |
| Pinnacle West Capital Corporation | PNW | $3.52 | $76.61 | 4.50% | 4.67% | 4.83% | 5.00% | 5.16% | 5.33% | 5.49% | 10.17% |
| Portland General Electric Company | POR | $2.00 | $43.02 | 6.00% | 5.92% | 5.83% | 5.75% | 5.66% | 5.58% | 5.49% | 10.65% |
| Southern Company | SO | $2.88 | $78.61 | 6.50% | 6.33% | 6.16% | 6.00% | 5.83% | 5.66% | 5.49% | 9.66% |
| Xcel Energy Inc. | XEL | $2.19 | $54.15 | 6.40% | 6.25% | 6.10% | 5.95% | 5.80% | 5.65% | 5.49% | 10.08% |
| Mean | | | | | 5.29% | 5.33% | 5.37% | 5.41% | 5.45% | 5.49% | 9.88% |
| Median | | | | | 5.29% | 5.33% | 5.37% | 5.41% | 5.45% | 5.49% | 9.79% |

Notes:
[1] Bloomberg Professional as of June 30, 2024
[2] Bloomberg Professional 30-day average as of June 30, 2024
[3] Min Exhibit PAC/2202, Col [5], [6], [7]
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Exhibit PAC/2204
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

**MULTI-STAGE DCF**

**MINIMUM FIRST STAGE GROWTH RATE**
**STOCK PRICE AVERAGING CONVENTION: 90 DAYS**

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Company | | Annualized Dividend | Stock Price | First Stage Gwth Rate | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Third Stage Growth Rate | ROE |
| Alliant Energy Corporation | LNT | $1.92 | $49.53 | 6.00% | 5.92% | 5.83% | 5.75% | 5.66% | 5.58% | 5.49% | 9.78% |
| Ameren Corporation | AEE | $2.68 | $71.82 | 5.50% | 5.50% | 5.50% | 5.50% | 5.50% | 5.50% | 5.49% | 9.50% |
| American Electric Power Company, Inc. | AEP | $3.52 | $85.75 | 6.10% | 6.00% | 5.90% | 5.80% | 5.70% | 5.60% | 5.49% | 10.07% |
| Avista Corporation | AVA | $1.90 | $34.85 | 6.00% | 5.92% | 5.83% | 5.75% | 5.66% | 5.58% | 5.49% | 11.57% |
| CMS Energy Corporation | CMS | $2.06 | $59.65 | 5.00% | 5.08% | 5.16% | 5.25% | 5.33% | 5.41% | 5.49% | 9.08% |
| Duke Energy Corporation | DUK | $4.10 | $97.53 | 5.00% | 5.08% | 5.16% | 5.25% | 5.33% | 5.41% | 5.49% | 9.89% |
| Entergy Corporation | ETR | $4.52 | $105.61 | 0.50% | 1.33% | 2.16% | 3.00% | 3.83% | 4.66% | 5.49% | 8.89% |
| Evergy, Inc. | EVRG | $2.57 | $52.07 | 5.00% | 5.08% | 5.16% | 5.25% | 5.33% | 5.41% | 5.49% | 10.67% |
| IDACORP, Inc. | IDA | $3.32 | $92.22 | 4.40% | 4.58% | 4.76% | 4.95% | 5.13% | 5.31% | 5.49% | 9.10% |
| NextEra Energy, Inc. | NEE | $2.06 | $66.86 | 8.00% | 7.58% | 7.16% | 6.75% | 6.33% | 5.91% | 5.49% | 9.31% |
| NorthWestern Corporation | NWE | $2.60 | $49.38 | 4.00% | 4.25% | 4.50% | 4.75% | 5.00% | 5.25% | 5.49% | 10.72% |
| OGE Energy Corporation | OGE | $1.67 | $34.52 | 5.00% | 5.08% | 5.16% | 5.25% | 5.33% | 5.41% | 5.49% | 10.58% |
| Pinnacle West Capital Corporation | PNW | $3.52 | $73.66 | 4.50% | 4.67% | 4.83% | 5.00% | 5.16% | 5.33% | 5.49% | 10.36% |
| Portland General Electric Company | POR | $2.00 | $41.88 | 6.00% | 5.92% | 5.83% | 5.75% | 5.66% | 5.58% | 5.49% | 10.80% |
| Southern Company | SO | $2.88 | $73.26 | 6.50% | 6.33% | 6.16% | 6.00% | 5.83% | 5.66% | 5.49% | 9.97% |
| Xcel Energy Inc. | XEL | $2.19 | $53.46 | 6.40% | 6.25% | 6.10% | 5.95% | 5.80% | 5.65% | 5.49% | 10.14% |
| Mean | | | | | 5.29% | 5.33% | 5.37% | 5.41% | 5.45% | 5.49% | 10.03% |
| Median | | | | | 5.29% | 5.33% | 5.37% | 5.41% | 5.45% | 5.49% | 10.02% |

Notes:
[1] Bloomberg Professional as of June 30, 2024
[2] Bloomberg Professional 90-day average as of June 30, 2024
[3] Min Exhibit PAC/2202, Col [5], [6], [7]
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Exhibit PAC/2204
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

**MULTI-STAGE DCF**

**MINIMUM FIRST STAGE GROWTH RATE**
**STOCK PRICE AVERAGING CONVENTION:** **180** **DAYS**

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Company | | Annualized Dividend | Stock Price | First Stage Gwth Rate | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Third Stage Growth Rate | ROE |
| Alliant Energy Corporation | LNT | $1.92 | $49.21 | 6.00% | 5.92% | 5.83% | 5.75% | 5.66% | 5.58% | 5.49% | 9.81% |
| Ameren Corporation | AEE | $2.68 | $72.14 | 5.50% | 5.50% | 5.50% | 5.50% | 5.50% | 5.50% | 5.49% | 9.48% |
| American Electric Power Company, Inc. | AEP | $3.52 | $81.37 | 6.10% | 6.00% | 5.90% | 5.80% | 5.70% | 5.60% | 5.49% | 10.32% |
| Avista Corporation | AVA | $1.90 | $34.01 | 6.00% | 5.92% | 5.83% | 5.75% | 5.66% | 5.58% | 5.49% | 11.72% |
| CMS Energy Corporation | CMS | $2.06 | $57.67 | 5.00% | 5.08% | 5.16% | 5.25% | 5.33% | 5.41% | 5.49% | 9.21% |
| Duke Energy Corporation | DUK | $4.10 | $94.20 | 5.00% | 5.08% | 5.16% | 5.25% | 5.33% | 5.41% | 5.49% | 10.05% |
| Entergy Corporation | ETR | $4.52 | $101.22 | 0.50% | 1.33% | 2.16% | 3.00% | 3.83% | 4.66% | 5.49% | 9.04% |
| Evergy, Inc. | EVRG | $2.57 | $50.70 | 5.00% | 5.08% | 5.16% | 5.25% | 5.33% | 5.41% | 5.49% | 10.82% |
| IDACORP, Inc. | IDA | $3.32 | $93.06 | 4.40% | 4.58% | 4.76% | 4.95% | 5.13% | 5.31% | 5.49% | 9.07% |
| NextEra Energy, Inc. | NEE | $2.06 | $61.96 | 8.00% | 7.58% | 7.16% | 6.75% | 6.33% | 5.91% | 5.49% | 9.62% |
| NorthWestern Corporation | NWE | $2.60 | $48.68 | 4.00% | 4.25% | 4.50% | 4.75% | 5.00% | 5.25% | 5.49% | 10.80% |
| OGE Energy Corporation | OGE | $1.67 | $34.06 | 5.00% | 5.08% | 5.16% | 5.25% | 5.33% | 5.41% | 5.49% | 10.65% |
| Pinnacle West Capital Corporation | PNW | $3.52 | $72.08 | 4.50% | 4.67% | 4.83% | 5.00% | 5.16% | 5.33% | 5.49% | 10.47% |
| Portland General Electric Company | POR | $2.00 | $41.10 | 6.00% | 5.92% | 5.83% | 5.75% | 5.66% | 5.58% | 5.49% | 10.90% |
| Southern Company | SO | $2.88 | $70.45 | 6.50% | 6.33% | 6.16% | 6.00% | 5.83% | 5.66% | 5.49% | 10.15% |
| Xcel Energy Inc. | XEL | $2.19 | $56.13 | 6.40% | 6.25% | 6.10% | 5.95% | 5.80% | 5.65% | 5.49% | 9.91% |
| Mean | | | | | 5.29% | 5.33% | 5.37% | 5.41% | 5.45% | 5.49% | 10.13% |
| Median | | | | | 5.29% | 5.33% | 5.37% | 5.41% | 5.45% | 5.49% | 10.10% |

Notes:
[1] Bloomberg Professional as of June 30, 2024
[2] Bloomberg Professional 180-day average as of June 30, 2024
[3] Min Exhibit PAC/2202, Col [5], [6], [7]
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Exhibit PAC/2204
[10] Equals internal rate of return of cash flows for Year 0 through Year 20

**MULTI-STAGE DCF**

**AVERAGE FIRST STAGE GROWTH RATE**
**STOCK PRICE AVERAGING CONVENTION: 30 DAYS**

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Company | | Annualized Dividend | Stock Price | First Stage Gwth Rate | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Third Stage Growth Rate | ROE |
| Alliant Energy Corporation | LNT | $1.92 | $50.66 | 6.13% | 6.03% | 5.92% | 5.81% | 5.71% | 5.60% | 5.49% | 9.72% |
| Ameren Corporation | AEE | $2.68 | $71.34 | 6.07% | 5.97% | 5.88% | 5.78% | 5.68% | 5.59% | 5.49% | 9.66% |
| American Electric Power Company, Inc. | AEP | $3.52 | $89.01 | 6.32% | 6.18% | 6.04% | 5.91% | 5.77% | 5.63% | 5.49% | 9.95% |
| Avista Corporation | AVA | $1.90 | $35.62 | 6.10% | 6.00% | 5.90% | 5.80% | 5.70% | 5.60% | 5.49% | 11.47% |
| CMS Energy Corporation | CMS | $2.06 | $60.92 | 6.73% | 6.53% | 6.32% | 6.11% | 5.91% | 5.70% | 5.49% | 9.39% |
| Duke Energy Corporation | DUK | $4.10 | $101.95 | 5.92% | 5.85% | 5.78% | 5.71% | 5.64% | 5.57% | 5.49% | 9.92% |
| Entergy Corporation | ETR | $4.52 | $108.95 | 4.87% | 4.97% | 5.08% | 5.18% | 5.28% | 5.39% | 5.49% | 9.79% |
| Evergy, Inc. | EVRG | $2.57 | $53.56 | 6.17% | 6.05% | 5.94% | 5.83% | 5.72% | 5.61% | 5.49% | 10.87% |
| IDACORP, Inc. | IDA | $3.32 | $93.69 | 4.70% | 4.83% | 4.96% | 5.10% | 5.23% | 5.36% | 5.49% | 9.11% |
| NextEra Energy, Inc. | NEE | $2.06 | $74.85 | 8.27% | 7.80% | 7.34% | 6.88% | 6.42% | 5.96% | 5.49% | 8.96% |
| NorthWestern Corporation | NWE | $2.60 | $50.34 | 4.25% | 4.46% | 4.66% | 4.87% | 5.08% | 5.29% | 5.49% | 10.69% |
| OGE Energy Corporation | OGE | $1.67 | $35.77 | 5.75% | 5.71% | 5.66% | 5.62% | 5.58% | 5.54% | 5.49% | 10.61% |
| Pinnacle West Capital Corporation | PNW | $3.52 | $76.61 | 6.63% | 6.44% | 6.25% | 6.06% | 5.87% | 5.68% | 5.49% | 10.78% |
| Portland General Electric Company | POR | $2.00 | $43.02 | 9.25% | 8.62% | 8.00% | 7.37% | 6.75% | 6.12% | 5.49% | 11.67% |
| Southern Company | SO | $2.88 | $78.61 | 6.93% | 6.69% | 6.45% | 6.21% | 5.97% | 5.73% | 5.49% | 9.77% |
| Xcel Energy Inc. | XEL | $2.19 | $54.15 | 6.71% | 6.51% | 6.30% | 6.10% | 5.90% | 5.70% | 5.49% | 10.16% |
| Mean | | | | | 6.17% | 6.03% | 5.90% | 5.76% | 5.63% | 5.49% | 10.16% |
| Median | | | | | 6.04% | 5.93% | 5.82% | 5.71% | 5.60% | 5.49% | 9.94% |

Notes:
[1] Bloomberg Professional as of June 30, 2024
[2] Bloomberg Professional 30-day average as of June 30, 2024
[3] Average Exhibit PAC/2202, Col [5], [6], [7]
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Exhibit PAC/2204
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

**MULTI-STAGE DCF**

**AVERAGE FIRST STAGE GROWTH RATE**
**STOCK PRICE AVERAGING CONVENTION: 90 DAYS**

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Company | | Annualized Dividend | Stock Price | First Stage Gwth Rate | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Third Stage Growth Rate | ROE |
| Alliant Energy Corporation | LNT | $1.92 | $49.53 | 6.13% | 6.03% | 5.92% | 5.81% | 5.71% | 5.60% | 5.49% | 9.81% |
| Ameren Corporation | AEE | $2.68 | $71.82 | 6.07% | 5.97% | 5.88% | 5.78% | 5.68% | 5.59% | 5.49% | 9.63% |
| American Electric Power Company, Inc. | AEP | $3.52 | $85.75 | 6.32% | 6.18% | 6.04% | 5.91% | 5.77% | 5.63% | 5.49% | 10.12% |
| Avista Corporation | AVA | $1.90 | $34.85 | 6.10% | 6.00% | 5.90% | 5.80% | 5.70% | 5.60% | 5.49% | 11.60% |
| CMS Energy Corporation | CMS | $2.06 | $59.65 | 6.73% | 6.53% | 6.32% | 6.11% | 5.91% | 5.70% | 5.49% | 9.47% |
| Duke Energy Corporation | DUK | $4.10 | $97.53 | 5.92% | 5.85% | 5.78% | 5.71% | 5.64% | 5.57% | 5.49% | 10.13% |
| Entergy Corporation | ETR | $4.52 | $105.61 | 4.87% | 4.97% | 5.08% | 5.18% | 5.28% | 5.39% | 5.49% | 9.93% |
| Evergy, Inc. | EVRG | $2.57 | $52.07 | 6.17% | 6.05% | 5.94% | 5.83% | 5.72% | 5.61% | 5.49% | 11.03% |
| IDACORP, Inc. | IDA | $3.32 | $92.22 | 4.70% | 4.83% | 4.96% | 5.10% | 5.23% | 5.36% | 5.49% | 9.17% |
| NextEra Energy, Inc. | NEE | $2.06 | $66.86 | 8.27% | 7.80% | 7.34% | 6.88% | 6.42% | 5.96% | 5.49% | 9.37% |
| NorthWestern Corporation | NWE | $2.60 | $49.38 | 4.25% | 4.46% | 4.66% | 4.87% | 5.08% | 5.29% | 5.49% | 10.80% |
| OGE Energy Corporation | OGE | $1.67 | $34.52 | 5.75% | 5.71% | 5.66% | 5.62% | 5.58% | 5.54% | 5.49% | 10.80% |
| Pinnacle West Capital Corporation | PNW | $3.52 | $73.66 | 6.63% | 6.44% | 6.25% | 6.06% | 5.87% | 5.68% | 5.49% | 10.99% |
| Portland General Electric Company | POR | $2.00 | $41.88 | 9.25% | 8.62% | 8.00% | 7.37% | 6.75% | 6.12% | 5.49% | 11.84% |
| Southern Company | SO | $2.88 | $73.26 | 6.93% | 6.69% | 6.45% | 6.21% | 5.97% | 5.73% | 5.49% | 10.09% |
| Xcel Energy Inc. | XEL | $2.19 | $53.46 | 6.71% | 6.51% | 6.30% | 6.10% | 5.90% | 5.70% | 5.49% | 10.22% |
| Mean | | | | | 6.17% | 6.03% | 5.90% | 5.76% | 5.63% | 5.49% | 10.31% |
| Median | | | | | 6.04% | 5.93% | 5.82% | 5.71% | 5.60% | 5.49% | 10.13% |

Notes:
[1] Bloomberg Professional as of June 30, 2024
[2] Bloomberg Professional 90-day average as of June 30, 2024
[3] Average Exhibit PAC/2202, Col [5], [6], [7]
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Exhibit PAC/2204
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

**MULTI-STAGE DCF**

**AVERAGE FIRST STAGE GROWTH RATE**
**STOCK PRICE AVERAGING CONVENTION:** **180** **DAYS**

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Company | | Annualized Dividend | Stock Price | First Stage Gwth Rate | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Third Stage Growth Rate | ROE |
| Alliant Energy Corporation | LNT | $1.92 | $49.21 | 6.13% | 6.03% | 5.92% | 5.81% | 5.71% | 5.60% | 5.49% | 9.84% |
| Ameren Corporation | AEE | $2.68 | $72.14 | 6.07% | 5.97% | 5.88% | 5.78% | 5.68% | 5.59% | 5.49% | 9.62% |
| American Electric Power Company, Inc. | AEP | $3.52 | $81.37 | 6.32% | 6.18% | 6.04% | 5.91% | 5.77% | 5.63% | 5.49% | 10.38% |
| Avista Corporation | AVA | $1.90 | $34.01 | 6.10% | 6.00% | 5.90% | 5.80% | 5.70% | 5.60% | 5.49% | 11.75% |
| CMS Energy Corporation | CMS | $2.06 | $57.67 | 6.73% | 6.53% | 6.32% | 6.11% | 5.91% | 5.70% | 5.49% | 9.61% |
| Duke Energy Corporation | DUK | $4.10 | $94.20 | 5.92% | 5.85% | 5.78% | 5.71% | 5.64% | 5.57% | 5.49% | 10.30% |
| Entergy Corporation | ETR | $4.52 | $101.22 | 4.87% | 4.97% | 5.08% | 5.18% | 5.28% | 5.39% | 5.49% | 10.13% |
| Evergy, Inc. | EVRG | $2.57 | $50.70 | 6.17% | 6.05% | 5.94% | 5.83% | 5.72% | 5.61% | 5.49% | 11.18% |
| IDACORP, Inc. | IDA | $3.32 | $93.06 | 4.70% | 4.83% | 4.96% | 5.10% | 5.23% | 5.36% | 5.49% | 9.14% |
| NextEra Energy, Inc. | NEE | $2.06 | $61.96 | 8.27% | 7.80% | 7.34% | 6.88% | 6.42% | 5.96% | 5.49% | 9.68% |
| NorthWestern Corporation | NWE | $2.60 | $48.68 | 4.25% | 4.46% | 4.66% | 4.87% | 5.08% | 5.29% | 5.49% | 10.88% |
| OGE Energy Corporation | OGE | $1.67 | $34.06 | 5.75% | 5.71% | 5.66% | 5.62% | 5.58% | 5.54% | 5.49% | 10.87% |
| Pinnacle West Capital Corporation | PNW | $3.52 | $72.08 | 6.63% | 6.44% | 6.25% | 6.06% | 5.87% | 5.68% | 5.49% | 11.12% |
| Portland General Electric Company | POR | $2.00 | $41.10 | 9.25% | 8.62% | 8.00% | 7.37% | 6.75% | 6.12% | 5.49% | 11.96% |
| Southern Company | SO | $2.88 | $70.45 | 6.93% | 6.69% | 6.45% | 6.21% | 5.97% | 5.73% | 5.49% | 10.27% |
| Xcel Energy Inc. | XEL | $2.19 | $56.13 | 6.71% | 6.51% | 6.30% | 6.10% | 5.90% | 5.70% | 5.49% | 9.99% |
| Mean | | | | | 6.17% | 6.03% | 5.90% | 5.76% | 5.63% | 5.49% | 10.42% |
| Median | | | | | 6.04% | 5.93% | 5.82% | 5.71% | 5.60% | 5.49% | 10.28% |

Notes:
[1] Bloomberg Professional as of June 30, 2024
[2] Bloomberg Professional 180-day average as of June 30, 2024
[3] Average Exhibit PAC/2202, Col [5], [6], [7]
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Exhibit PAC/2204
[10] Equals internal rate of return of cash flows for Year 0 through Year 20

**MULTI-STAGE DCF**

**MAXIMUM FIRST STAGE GROWTH RATE**
**STOCK PRICE AVERAGING CONVENTION: 30 DAYS**

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Company | | Annualized Dividend | Stock Price | First Stage Gwth Rate | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Third Stage Growth Rate | ROE |
| Alliant Energy Corporation | LNT | $1.92 | $50.66 | 6.30% | 6.17% | 6.03% | 5.90% | 5.76% | 5.63% | 5.49% | 9.76% |
| Ameren Corporation | AEE | $2.68 | $71.34 | 6.50% | 6.33% | 6.16% | 6.00% | 5.83% | 5.66% | 5.49% | 9.77% |
| American Electric Power Company, Inc. | AEP | $3.52 | $89.01 | 6.50% | 6.33% | 6.16% | 6.00% | 5.83% | 5.66% | 5.49% | 10.00% |
| Avista Corporation | AVA | $1.90 | $35.62 | 6.20% | 6.08% | 5.96% | 5.85% | 5.73% | 5.61% | 5.49% | 11.50% |
| CMS Energy Corporation | CMS | $2.06 | $60.92 | 7.60% | 7.25% | 6.90% | 6.55% | 6.20% | 5.85% | 5.49% | 9.59% |
| Duke Energy Corporation | DUK | $4.10 | $101.95 | 6.66% | 6.47% | 6.27% | 6.08% | 5.88% | 5.69% | 5.49% | 10.12% |
| Entergy Corporation | ETR | $4.52 | $108.95 | 7.30% | 7.00% | 6.70% | 6.40% | 6.10% | 5.80% | 5.49% | 10.44% |
| Evergy, Inc. | EVRG | $2.57 | $53.56 | 7.50% | 7.17% | 6.83% | 6.50% | 6.16% | 5.83% | 5.49% | 11.29% |
| IDACORP, Inc. | IDA | $3.32 | $93.69 | 5.00% | 5.08% | 5.16% | 5.25% | 5.33% | 5.41% | 5.49% | 9.18% |
| NextEra Energy, Inc. | NEE | $2.06 | $74.85 | 8.60% | 8.08% | 7.56% | 7.05% | 6.53% | 6.01% | 5.49% | 9.03% |
| NorthWestern Corporation | NWE | $2.60 | $50.34 | 4.50% | 4.67% | 4.83% | 5.00% | 5.16% | 5.33% | 5.49% | 10.77% |
| OGE Energy Corporation | OGE | $1.67 | $35.77 | 6.50% | 6.33% | 6.16% | 6.00% | 5.83% | 5.66% | 5.49% | 10.84% |
| Pinnacle West Capital Corporation | PNW | $3.52 | $76.61 | 8.20% | 7.75% | 7.30% | 6.85% | 6.40% | 5.95% | 5.49% | 11.26% |
| Portland General Electric Company | POR | $2.00 | $43.02 | 12.50% | 11.33% | 10.16% | 9.00% | 7.83% | 6.66% | 5.49% | 12.81% |
| Southern Company | SO | $2.88 | $78.61 | 7.30% | 7.00% | 6.70% | 6.40% | 6.10% | 5.80% | 5.49% | 9.86% |
| Xcel Energy Inc. | XEL | $2.19 | $54.15 | 7.00% | 6.75% | 6.50% | 6.25% | 6.00% | 5.75% | 5.49% | 10.24% |
| Mean | | | | | 6.86% | 6.59% | 6.31% | 6.04% | 5.77% | 5.49% | 10.40% |
| Median | | | | | 6.61% | 6.38% | 6.16% | 5.94% | 5.72% | 5.49% | 10.18% |

Notes:
[1] Bloomberg Professional as of June 30, 2024
[2] Bloomberg Professional 30-day average as of June 30, 2024
[3] Max Exhibit PAC/2202, Col [5], [6], [7]
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Exhibit PAC/2204
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

**MULTI-STAGE DCF**

**MAXIMUM FIRST STAGE GROWTH RATE**
**STOCK PRICE AVERAGING CONVENTION:** **90** **DAYS**

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Company | | Annualized Dividend | Stock Price | First Stage Gwth Rate | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Third Stage Growth Rate | ROE |
| Alliant Energy Corporation | LNT | $1.92 | $49.53 | 6.30% | 6.17% | 6.03% | 5.90% | 5.76% | 5.63% | 5.49% | 9.86% |
| Ameren Corporation | AEE | $2.68 | $71.82 | 6.50% | 6.33% | 6.16% | 6.00% | 5.83% | 5.66% | 5.49% | 9.74% |
| American Electric Power Company, Inc. | AEP | $3.52 | $85.75 | 6.50% | 6.33% | 6.16% | 6.00% | 5.83% | 5.66% | 5.49% | 10.17% |
| Avista Corporation | AVA | $1.90 | $34.85 | 6.20% | 6.08% | 5.96% | 5.85% | 5.73% | 5.61% | 5.49% | 11.63% |
| CMS Energy Corporation | CMS | $2.06 | $59.65 | 7.60% | 7.25% | 6.90% | 6.55% | 6.20% | 5.85% | 5.49% | 9.68% |
| Duke Energy Corporation | DUK | $4.10 | $97.53 | 6.66% | 6.47% | 6.27% | 6.08% | 5.88% | 5.69% | 5.49% | 10.33% |
| Entergy Corporation | ETR | $4.52 | $105.61 | 7.30% | 7.00% | 6.70% | 6.40% | 6.10% | 5.80% | 5.49% | 10.60% |
| Evergy, Inc. | EVRG | $2.57 | $52.07 | 7.50% | 7.17% | 6.83% | 6.50% | 6.16% | 5.83% | 5.49% | 11.46% |
| IDACORP, Inc. | IDA | $3.32 | $92.22 | 5.00% | 5.08% | 5.16% | 5.25% | 5.33% | 5.41% | 5.49% | 9.24% |
| NextEra Energy, Inc. | NEE | $2.06 | $66.86 | 8.60% | 8.08% | 7.56% | 7.05% | 6.53% | 6.01% | 5.49% | 9.45% |
| NorthWestern Corporation | NWE | $2.60 | $49.38 | 4.50% | 4.67% | 4.83% | 5.00% | 5.16% | 5.33% | 5.49% | 10.87% |
| OGE Energy Corporation | OGE | $1.67 | $34.52 | 6.50% | 6.33% | 6.16% | 6.00% | 5.83% | 5.66% | 5.49% | 11.03% |
| Pinnacle West Capital Corporation | PNW | $3.52 | $73.66 | 8.20% | 7.75% | 7.30% | 6.85% | 6.40% | 5.95% | 5.49% | 11.49% |
| Portland General Electric Company | POR | $2.00 | $41.88 | 12.50% | 11.33% | 10.16% | 9.00% | 7.83% | 6.66% | 5.49% | 13.00% |
| Southern Company | SO | $2.88 | $73.26 | 7.30% | 7.00% | 6.70% | 6.40% | 6.10% | 5.80% | 5.49% | 10.18% |
| Xcel Energy Inc. | XEL | $2.19 | $53.46 | 7.00% | 6.75% | 6.50% | 6.25% | 6.00% | 5.75% | 5.49% | 10.30% |
| Mean | | | | | 6.86% | 6.59% | 6.31% | 6.04% | 5.77% | 5.49% | 10.57% |
| Median | | | | | 6.61% | 6.38% | 6.16% | 5.94% | 5.72% | 5.49% | 10.31% |

Notes:
[1] Bloomberg Professional as of June 30, 2024
[2] Bloomberg Professional 90-day average as of June 30, 2024
[3] Max Exhibit PAC/2202, Col [5], [6], [7]
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Exhibit PAC/2204
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

**MULTI-STAGE DCF**

**MAXIMUM FIRST STAGE GROWTH RATE**
**STOCK PRICE AVERAGING CONVENTION:** **180** **DAYS**

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Company | | Annualized Dividend | Stock Price | First Stage Gwth Rate | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Third Stage Growth Rate | ROE |
| Alliant Energy Corporation | LNT | $1.92 | $49.21 | 6.30% | 6.17% | 6.03% | 5.90% | 5.76% | 5.63% | 5.49% | 9.89% |
| Ameren Corporation | AEE | $2.68 | $72.14 | 6.50% | 6.33% | 6.16% | 6.00% | 5.83% | 5.66% | 5.49% | 9.72% |
| American Electric Power Company, Inc. | AEP | $3.52 | $81.37 | 6.50% | 6.33% | 6.16% | 6.00% | 5.83% | 5.66% | 5.49% | 10.43% |
| Avista Corporation | AVA | $1.90 | $34.01 | 6.20% | 6.08% | 5.96% | 5.85% | 5.73% | 5.61% | 5.49% | 11.79% |
| CMS Energy Corporation | CMS | $2.06 | $57.67 | 7.60% | 7.25% | 6.90% | 6.55% | 6.20% | 5.85% | 5.49% | 9.83% |
| Duke Energy Corporation | DUK | $4.10 | $94.20 | 6.66% | 6.47% | 6.27% | 6.08% | 5.88% | 5.69% | 5.49% | 10.50% |
| Entergy Corporation | ETR | $4.52 | $101.22 | 7.30% | 7.00% | 6.70% | 6.40% | 6.10% | 5.80% | 5.49% | 10.83% |
| Evergy, Inc. | EVRG | $2.57 | $50.70 | 7.50% | 7.17% | 6.83% | 6.50% | 6.16% | 5.83% | 5.49% | 11.62% |
| IDACORP, Inc. | IDA | $3.32 | $93.06 | 5.00% | 5.08% | 5.16% | 5.25% | 5.33% | 5.41% | 5.49% | 9.20% |
| NextEra Energy, Inc. | NEE | $2.06 | $61.96 | 8.60% | 8.08% | 7.56% | 7.05% | 6.53% | 6.01% | 5.49% | 9.76% |
| NorthWestern Corporation | NWE | $2.60 | $48.68 | 4.50% | 4.67% | 4.83% | 5.00% | 5.16% | 5.33% | 5.49% | 10.95% |
| OGE Energy Corporation | OGE | $1.67 | $34.06 | 6.50% | 6.33% | 6.16% | 6.00% | 5.83% | 5.66% | 5.49% | 11.11% |
| Pinnacle West Capital Corporation | PNW | $3.52 | $72.08 | 8.20% | 7.75% | 7.30% | 6.85% | 6.40% | 5.95% | 5.49% | 11.63% |
| Portland General Electric Company | POR | $2.00 | $41.10 | 12.50% | 11.33% | 10.16% | 9.00% | 7.83% | 6.66% | 5.49% | 13.14% |
| Southern Company | SO | $2.88 | $70.45 | 7.30% | 7.00% | 6.70% | 6.40% | 6.10% | 5.80% | 5.49% | 10.37% |
| Xcel Energy Inc. | XEL | $2.19 | $56.13 | 7.00% | 6.75% | 6.50% | 6.25% | 6.00% | 5.75% | 5.49% | 10.07% |
| Mean | | | | | 6.86% | 6.59% | 6.31% | 6.04% | 5.77% | 5.49% | 10.68% |
| Median | | | | | 6.61% | 6.38% | 6.16% | 5.94% | 5.72% | 5.49% | 10.47% |

Notes:
[1] Bloomberg Professional as of June 30, 2024
[2] Bloomberg Professional 180-day average as of June 30, 2024
[3] Max Exhibit PAC/2202, Col [5], [6], [7]
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Exhibit PAC/2204
[10] Equals internal rate of return of cash flows for Year 0 through Year 20

Docket No. UE 433
Exhibit PAC/2204
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Gross Domestic Product Growth**

**July 2024**

# CALCULATION OF LONG-TERM GROWTH RATE FOR MULTI-STAGE DCF

| | | |
|---|---|---|
| **Historical GDP Growth** | | |
| Real GDP ($ Billions) [1] | 1929 | $ 1,191.1 |
| | 2023 | $ 22,376.9 |
| Compound Annual Growth Rate | | **3.17%** |
| | | |
| **Inflation Forecast** | | |
| Consumer Price Index (YoY % Change) [2] | 2031-2035 | 2.20% |
| | | |
| Consumer Price Index (All-Urban) [3] | 2035 | 3.96 |
| | 2050 | 5.54 |
| Compound Annual Growth Rate | | 2.26% |
| | | |
| GDP Chain-type Price Index (2012=1.000) [3] | 2035 | 1.73 |
| | 2050 | 2.43 |
| Compound Annual Growth Rate | | 2.30% |
| | | |
| **Average Inflation Forecast** | | **2.25%** |
| | | |
| **Long-Term GDP Growth Rate** | | **5.49%** |

Notes:

[1] Bureau of Economic Analysis, June 27, 2024.

[2] *Blue Chip Financial Forecasts*, Vol. 43, No. 6, May 31, 2024, at 14.

[3] Energy Information Administration, Annual Energy Outlook 2023, at Table 20, March 16, 2023

Docket No. UE 433
Exhibit PAC/2205
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Capital Asset Pricing Model and Empirical Capital Asset Pricing Model**

**July 2024**

**CAPITAL ASSET PRICING MODEL**
**CURRENT RISK FREE RATE AND VALUE LINE BETA**

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

| | | [1] | [2] | [3] | [4] | [5] | [6] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Current 30-day average of 30-year U.S. Treasury bond yield | Beta (β) | Market Return (Rm) | Market Risk Premium (Rm − Rf) | CAPM ROE (K) | ECAPM ROE (K) |
| Alliant Energy Corporation | LNT | 4.50% | 0.90 | 12.65% | 8.15% | 11.84% | 12.04% |
| Ameren Corporation | AEE | 4.50% | 0.90 | 12.65% | 8.15% | 11.84% | 12.04% |
| American Electric Power Company, Inc. | AEP | 4.50% | 0.85 | 12.65% | 8.15% | 11.43% | 11.74% |
| Avista Corporation | AVA | 4.50% | 0.95 | 12.65% | 8.15% | 12.25% | 12.35% |
| CMS Energy Corporation | CMS | 4.50% | 0.85 | 12.65% | 8.15% | 11.43% | 11.74% |
| Duke Energy Corporation | DUK | 4.50% | 0.90 | 12.65% | 8.15% | 11.84% | 12.04% |
| Entergy Corporation | ETR | 4.50% | 1.00 | 12.65% | 8.15% | 12.65% | 12.65% |
| Evergy, Inc. | EVRG | 4.50% | 0.95 | 12.65% | 8.15% | 12.25% | 12.35% |
| IDACORP, Inc. | IDA | 4.50% | 0.85 | 12.65% | 8.15% | 11.43% | 11.74% |
| NextEra Energy, Inc. | NEE | 4.50% | 1.05 | 12.65% | 8.15% | 13.06% | 12.96% |
| NorthWestern Corporation | NWE | 4.50% | 0.95 | 12.65% | 8.15% | 12.25% | 12.35% |
| OGE Energy Corporation | OGE | 4.50% | 1.05 | 12.65% | 8.15% | 13.06% | 12.96% |
| Pinnacle West Capital Corporation | PNW | 4.50% | 0.95 | 12.65% | 8.15% | 12.25% | 12.35% |
| Portland General Electric Company | POR | 4.50% | 0.90 | 12.65% | 8.15% | 11.84% | 12.04% |
| Southern Company | SO | 4.50% | 0.95 | 12.65% | 8.15% | 12.25% | 12.35% |
| Xcel Energy Inc. | XEL | 4.50% | 0.85 | 12.65% | 8.15% | 11.43% | 11.74% |
| Mean | | | | | | 12.07% | 12.22% |
| Median | | | | | | 12.04% | 12.20% |

Notes:
[1] Bloomberg Professional 30-day average as of June 30, 2024
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

**CAPITAL ASSET PRICING MODEL**
**NEAR TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA**

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

| Company | Ticker | [1] Near-term projected 30-year U.S. Treasury bond yield (Q4 2024 - Q4 2025) | [2] Beta (β) | [3] Market Return (Rm) | [4] Market Risk Premium (Rm − Rf) | [5] CAPM ROE (K) | [6] ECAPM ROE (K) |
|---|---|---|---|---|---|---|---|
| Alliant Energy Corporation | LNT | 4.32% | 0.90 | 12.65% | 8.33% | 11.82% | 12.03% |
| Ameren Corporation | AEE | 4.32% | 0.90 | 12.65% | 8.33% | 11.82% | 12.03% |
| American Electric Power Company, Inc. | AEP | 4.32% | 0.85 | 12.65% | 8.33% | 11.40% | 11.72% |
| Avista Corporation | AVA | 4.32% | 0.95 | 12.65% | 8.33% | 12.24% | 12.34% |
| CMS Energy Corporation | CMS | 4.32% | 0.85 | 12.65% | 8.33% | 11.40% | 11.72% |
| Duke Energy Corporation | DUK | 4.32% | 0.90 | 12.65% | 8.33% | 11.82% | 12.03% |
| Entergy Corporation | ETR | 4.32% | 1.00 | 12.65% | 8.33% | 12.65% | 12.65% |
| Evergy, Inc. | EVRG | 4.32% | 0.95 | 12.65% | 8.33% | 12.24% | 12.34% |
| IDACORP, Inc. | IDA | 4.32% | 0.85 | 12.65% | 8.33% | 11.40% | 11.72% |
| NextEra Energy, Inc. | NEE | 4.32% | 1.05 | 12.65% | 8.33% | 13.07% | 12.97% |
| NorthWestern Corporation | NWE | 4.32% | 0.95 | 12.65% | 8.33% | 12.24% | 12.34% |
| OGE Energy Corporation | OGE | 4.32% | 1.05 | 12.65% | 8.33% | 13.07% | 12.97% |
| Pinnacle West Capital Corporation | PNW | 4.32% | 0.95 | 12.65% | 8.33% | 12.24% | 12.34% |
| Portland General Electric Company | POR | 4.32% | 0.90 | 12.65% | 8.33% | 11.82% | 12.03% |
| Southern Company | SO | 4.32% | 0.95 | 12.65% | 8.33% | 12.24% | 12.34% |
| Xcel Energy Inc. | XEL | 4.32% | 0.85 | 12.65% | 8.33% | 11.40% | 11.72% |
| Mean | | | | | | 12.06% | 12.21% |
| Median | | | | | | 12.03% | 12.19% |

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 7, June 30, 2024, at 2
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

**CAPITAL ASSET PRICING MODEL**
**LONG-TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA**

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

| | | [1] | [2] | [3] | [4] | [5] | [6] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Projected 30-year U.S. Treasury bond yield (2026 - 2030) | Beta (β) | Market Return (Rm) | Market Risk Premium (Rm − Rf) | CAPM ROE (K) | ECAPM ROE (K) |
| Alliant Energy Corporation | LNT | 4.30% | 0.90 | 12.65% | 8.35% | 11.82% | 12.03% |
| Ameren Corporation | AEE | 4.30% | 0.90 | 12.65% | 8.35% | 11.82% | 12.03% |
| American Electric Power Company, Inc. | AEP | 4.30% | 0.85 | 12.65% | 8.35% | 11.40% | 11.71% |
| Avista Corporation | AVA | 4.30% | 0.95 | 12.65% | 8.35% | 12.24% | 12.34% |
| CMS Energy Corporation | CMS | 4.30% | 0.85 | 12.65% | 8.35% | 11.40% | 11.71% |
| Duke Energy Corporation | DUK | 4.30% | 0.90 | 12.65% | 8.35% | 11.82% | 12.03% |
| Entergy Corporation | ETR | 4.30% | 1.00 | 12.65% | 8.35% | 12.65% | 12.65% |
| Evergy, Inc. | EVRG | 4.30% | 0.95 | 12.65% | 8.35% | 12.24% | 12.34% |
| IDACORP, Inc. | IDA | 4.30% | 0.85 | 12.65% | 8.35% | 11.40% | 11.71% |
| NextEra Energy, Inc. | NEE | 4.30% | 1.05 | 12.65% | 8.35% | 13.07% | 12.97% |
| NorthWestern Corporation | NWE | 4.30% | 0.95 | 12.65% | 8.35% | 12.24% | 12.34% |
| OGE Energy Corporation | OGE | 4.30% | 1.05 | 12.65% | 8.35% | 13.07% | 12.97% |
| Pinnacle West Capital Corporation | PNW | 4.30% | 0.95 | 12.65% | 8.35% | 12.24% | 12.34% |
| Portland General Electric Company | POR | 4.30% | 0.90 | 12.65% | 8.35% | 11.82% | 12.03% |
| Southern Company | SO | 4.30% | 0.95 | 12.65% | 8.35% | 12.24% | 12.34% |
| Xcel Energy Inc. | XEL | 4.30% | 0.85 | 12.65% | 8.35% | 11.40% | 11.71% |
| Mean | | | | | | 12.05% | 12.20% |
| Median | | | | | | 12.03% | 12.18% |

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, at 14.
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

**CAPITAL ASSET PRICING MODEL**
**CURRENT RISK FREE RATE AND BLOOMBERG BETA**

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

| | | [1] | [2] | [3] | [4] | [5] | [6] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Current 30-day average of 30-year U.S. Treasury bond yield | Beta (β) | Market Return (Rm) | Market Risk Premium (Rm − Rf) | CAPM ROE (K) | ECAPM ROE (K) |
| Alliant Energy Corporation | LNT | 4.50% | 0.78 | 12.65% | 8.15% | 10.87% | 11.31% |
| Ameren Corporation | AEE | 4.50% | 0.74 | 12.65% | 8.15% | 10.54% | 11.07% |
| American Electric Power Company, Inc. | AEP | 4.50% | 0.75 | 12.65% | 8.15% | 10.65% | 11.15% |
| Avista Corporation | AVA | 4.50% | 0.75 | 12.65% | 8.15% | 10.63% | 11.14% |
| CMS Energy Corporation | CMS | 4.50% | 0.74 | 12.65% | 8.15% | 10.54% | 11.07% |
| Duke Energy Corporation | DUK | 4.50% | 0.71 | 12.65% | 8.15% | 10.32% | 10.90% |
| Entergy Corporation | ETR | 4.50% | 0.85 | 12.65% | 8.15% | 11.45% | 11.75% |
| Evergy, Inc. | EVRG | 4.50% | 0.77 | 12.65% | 8.15% | 10.80% | 11.27% |
| IDACORP, Inc. | IDA | 4.50% | 0.78 | 12.65% | 8.15% | 10.90% | 11.34% |
| NextEra Energy, Inc. | NEE | 4.50% | 0.81 | 12.65% | 8.15% | 11.10% | 11.49% |
| NorthWestern Corporation | NWE | 4.50% | 0.86 | 12.65% | 8.15% | 11.50% | 11.79% |
| OGE Energy Corporation | OGE | 4.50% | 0.91 | 12.65% | 8.15% | 11.91% | 12.09% |
| Pinnacle West Capital Corporation | PNW | 4.50% | 0.81 | 12.65% | 8.15% | 11.10% | 11.49% |
| Portland General Electric Company | POR | 4.50% | 0.78 | 12.65% | 8.15% | 10.84% | 11.29% |
| Southern Company | SO | 4.50% | 0.77 | 12.65% | 8.15% | 10.80% | 11.26% |
| Xcel Energy Inc. | XEL | 4.50% | 0.72 | 12.65% | 8.15% | 10.40% | 10.96% |
| Mean | | | | | | 10.90% | 11.34% |
| Median | | | | | | 10.82% | 11.28% |

Notes:
[1] Bloomberg Professional 30-day average as of June 30, 2024
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

**CAPITAL ASSET PRICING MODEL**
**NEAR TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA**

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

| | | [1] | [2] | [3] | [4] | [5] | [6] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Near-term projected 30-year U.S. Treasury bond yield (Q4 2024 - Q4 2025) | Beta (β) | Market Return (Rm) | Market Risk Premium (Rm − Rf) | CAPM ROE (K) | ECAPM ROE (K) |
| Alliant Energy Corporation | LNT | 4.32% | 0.78 | 12.65% | 8.33% | 10.83% | 11.28% |
| Ameren Corporation | AEE | 4.32% | 0.74 | 12.65% | 8.33% | 10.50% | 11.04% |
| American Electric Power Company, Inc. | AEP | 4.32% | 0.75 | 12.65% | 8.33% | 10.61% | 11.12% |
| Avista Corporation | AVA | 4.32% | 0.75 | 12.65% | 8.33% | 10.59% | 11.11% |
| CMS Energy Corporation | CMS | 4.32% | 0.74 | 12.65% | 8.33% | 10.50% | 11.04% |
| Duke Energy Corporation | DUK | 4.32% | 0.71 | 12.65% | 8.33% | 10.27% | 10.86% |
| Entergy Corporation | ETR | 4.32% | 0.85 | 12.65% | 8.33% | 11.42% | 11.73% |
| Evergy, Inc. | EVRG | 4.32% | 0.77 | 12.65% | 8.33% | 10.76% | 11.24% |
| IDACORP, Inc. | IDA | 4.32% | 0.78 | 12.65% | 8.33% | 10.86% | 11.31% |
| NextEra Energy, Inc. | NEE | 4.32% | 0.81 | 12.65% | 8.33% | 11.07% | 11.46% |
| NorthWestern Corporation | NWE | 4.32% | 0.86 | 12.65% | 8.33% | 11.47% | 11.77% |
| OGE Energy Corporation | OGE | 4.32% | 0.91 | 12.65% | 8.33% | 11.89% | 12.08% |
| Pinnacle West Capital Corporation | PNW | 4.32% | 0.81 | 12.65% | 8.33% | 11.07% | 11.46% |
| Portland General Electric Company | POR | 4.32% | 0.78 | 12.65% | 8.33% | 10.80% | 11.26% |
| Southern Company | SO | 4.32% | 0.77 | 12.65% | 8.33% | 10.76% | 11.23% |
| Xcel Energy Inc. | XEL | 4.32% | 0.72 | 12.65% | 8.33% | 10.35% | 10.93% |
| Mean | | | | | | 10.86% | 11.31% |
| Median | | | | | | 10.78% | 11.25% |

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 7, June 30, 2024, at 2
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

**CAPITAL ASSET PRICING MODEL**
**LONG-TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA**

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

| | | [1] | [2] | [3] | [4] | [5] | [6] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Projected 30-year U.S. Treasury bond yield (2026 - 2030) | Beta (β) | Market Return (Rm) | Market Risk Premium (Rm − Rf) | CAPM ROE (K) | ECAPM ROE (K) |
| Alliant Energy Corporation | LNT | 4.30% | 0.78 | 12.65% | 8.35% | 10.82% | 11.28% |
| Ameren Corporation | AEE | 4.30% | 0.74 | 12.65% | 8.35% | 10.49% | 11.03% |
| American Electric Power Company, Inc. | AEP | 4.30% | 0.75 | 12.65% | 8.35% | 10.60% | 11.11% |
| Avista Corporation | AVA | 4.30% | 0.75 | 12.65% | 8.35% | 10.58% | 11.10% |
| CMS Energy Corporation | CMS | 4.30% | 0.74 | 12.65% | 8.35% | 10.49% | 11.03% |
| Duke Energy Corporation | DUK | 4.30% | 0.71 | 12.65% | 8.35% | 10.26% | 10.86% |
| Entergy Corporation | ETR | 4.30% | 0.85 | 12.65% | 8.35% | 11.42% | 11.73% |
| Evergy, Inc. | EVRG | 4.30% | 0.77 | 12.65% | 8.35% | 10.76% | 11.23% |
| IDACORP, Inc. | IDA | 4.30% | 0.78 | 12.65% | 8.35% | 10.85% | 11.30% |
| NextEra Energy, Inc. | NEE | 4.30% | 0.81 | 12.65% | 8.35% | 11.06% | 11.46% |
| NorthWestern Corporation | NWE | 4.30% | 0.86 | 12.65% | 8.35% | 11.47% | 11.76% |
| OGE Energy Corporation | OGE | 4.30% | 0.91 | 12.65% | 8.35% | 11.89% | 12.08% |
| Pinnacle West Capital Corporation | PNW | 4.30% | 0.81 | 12.65% | 8.35% | 11.06% | 11.46% |
| Portland General Electric Company | POR | 4.30% | 0.78 | 12.65% | 8.35% | 10.79% | 11.26% |
| Southern Company | SO | 4.30% | 0.77 | 12.65% | 8.35% | 10.75% | 11.23% |
| Xcel Energy Inc. | XEL | 4.30% | 0.72 | 12.65% | 8.35% | 10.34% | 10.92% |
| Mean | | | | | | 10.85% | 11.30% |
| Median | | | | | | 10.78% | 11.25% |

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, at 14.
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

**CAPITAL ASSET PRICING MODEL**
**CURRENT RISK FREE RATE AND LONG-TERM VALUE LINE BETA**

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

| Company | Ticker | [1] Current 30-day average of 30-year U.S. Treasury bond yield | [2] Beta (β) | [3] Market Return (Rm) | [4] Market Risk Premium (Rm − Rf) | [5] CAPM ROE (K) | [6] ECAPM ROE (K) |
|---|---|---|---|---|---|---|---|
| Alliant Energy Corporation | LNT | 4.50% | 0.76 | 12.65% | 8.15% | 10.73% | 11.21% |
| Ameren Corporation | AEE | 4.50% | 0.74 | 12.65% | 8.15% | 10.54% | 11.07% |
| American Electric Power Company, Inc. | AEP | 4.50% | 0.69 | 12.65% | 8.15% | 10.10% | 10.74% |
| Avista Corporation | AVA | 4.50% | 0.80 | 12.65% | 8.15% | 10.99% | 11.40% |
| CMS Energy Corporation | CMS | 4.50% | 0.70 | 12.65% | 8.15% | 10.25% | 10.85% |
| Duke Energy Corporation | DUK | 4.50% | 0.69 | 12.65% | 8.15% | 10.10% | 10.74% |
| Entergy Corporation | ETR | 4.50% | 0.76 | 12.65% | 8.15% | 10.73% | 11.21% |
| Evergy, Inc. | EVRG | 4.50% | 0.94 | 12.65% | 8.15% | 12.15% | 12.27% |
| IDACORP, Inc. | IDA | 4.50% | 0.74 | 12.65% | 8.15% | 10.54% | 11.07% |
| NextEra Energy, Inc. | NEE | 4.50% | 0.75 | 12.65% | 8.15% | 10.65% | 11.15% |
| NorthWestern Corporation | NWE | 4.50% | 0.76 | 12.65% | 8.15% | 10.73% | 11.21% |
| OGE Energy Corporation | OGE | 4.50% | 0.94 | 12.65% | 8.15% | 12.17% | 12.29% |
| Pinnacle West Capital Corporation | PNW | 4.50% | 0.75 | 12.65% | 8.15% | 10.65% | 11.15% |
| Portland General Electric Company | POR | 4.50% | 0.76 | 12.65% | 8.15% | 10.73% | 11.21% |
| Southern Company | SO | 4.50% | 0.68 | 12.65% | 8.15% | 10.06% | 10.71% |
| Xcel Energy Inc. | XEL | 4.50% | 0.67 | 12.65% | 8.15% | 9.99% | 10.65% |
| Mean | | | | | | 10.69% | 11.18% |
| Median | | | | | | 10.65% | 11.15% |

Notes:
[1] Bloomberg Professional 30-day average as of June 30, 2024
[2] Source: LT Beta
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

**CAPITAL ASSET PRICING MODEL**
**NEAR-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA**

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

| Company | Ticker | [1] Near-term projected 30-year U.S. Treasury bond yield (Q4 2024 - Q4 2025) | [2] Beta (β) | [3] Market Return (Rm) | [4] Market Risk Premium (Rm − Rf) | [5] CAPM ROE (K) | [6] ECAPM ROE (K) |
|---|---|---|---|---|---|---|---|
| Alliant Energy Corporation | LNT | 4.32% | 0.76 | 12.65% | 8.33% | 10.68% | 11.18% |
| Ameren Corporation | AEE | 4.32% | 0.74 | 12.65% | 8.33% | 10.50% | 11.03% |
| American Electric Power Company, Inc. | AEP | 4.32% | 0.69 | 12.65% | 8.33% | 10.04% | 10.69% |
| Avista Corporation | AVA | 4.32% | 0.80 | 12.65% | 8.33% | 10.95% | 11.38% |
| CMS Energy Corporation | CMS | 4.32% | 0.70 | 12.65% | 8.33% | 10.19% | 10.81% |
| Duke Energy Corporation | DUK | 4.32% | 0.69 | 12.65% | 8.33% | 10.04% | 10.69% |
| Entergy Corporation | ETR | 4.32% | 0.76 | 12.65% | 8.33% | 10.68% | 11.18% |
| Evergy, Inc. | EVRG | 4.32% | 0.94 | 12.65% | 8.33% | 12.13% | 12.26% |
| IDACORP, Inc. | IDA | 4.32% | 0.74 | 12.65% | 8.33% | 10.50% | 11.03% |
| NextEra Energy, Inc. | NEE | 4.32% | 0.75 | 12.65% | 8.33% | 10.61% | 11.12% |
| NorthWestern Corporation | NWE | 4.32% | 0.76 | 12.65% | 8.33% | 10.68% | 11.18% |
| OGE Energy Corporation | OGE | 4.32% | 0.94 | 12.65% | 8.33% | 12.16% | 12.29% |
| Pinnacle West Capital Corporation | PNW | 4.32% | 0.75 | 12.65% | 8.33% | 10.61% | 11.12% |
| Portland General Electric Company | POR | 4.32% | 0.76 | 12.65% | 8.33% | 10.68% | 11.18% |
| Southern Company | SO | 4.32% | 0.68 | 12.65% | 8.33% | 10.00% | 10.67% |
| Xcel Energy Inc. | XEL | 4.32% | 0.67 | 12.65% | 8.33% | 9.93% | 10.61% |
| Mean | | | | | | 10.65% | 11.15% |
| Median | | | | | | 10.61% | 11.12% |

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 7, June 30, 2024, at 2
[2] Source: LT Beta
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

**CAPITAL ASSET PRICING MODEL**
**LONG-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA**

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

| | | [1] | [2] | [3] | [4] | [5] | [6] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Projected 30-year U.S. Treasury bond yield (2026 - 2030) | Beta (β) | Market Return (Rm) | Market Risk Premium (Rm − Rf) | CAPM ROE (K) | ECAPM ROE (K) |
| Alliant Energy Corporation | LNT | 4.30% | 0.76 | 12.65% | 8.35% | 10.68% | 11.17% |
| Ameren Corporation | AEE | 4.30% | 0.74 | 12.65% | 8.35% | 10.49% | 11.03% |
| American Electric Power Company, Inc. | AEP | 4.30% | 0.69 | 12.65% | 8.35% | 10.03% | 10.69% |
| Avista Corporation | AVA | 4.30% | 0.80 | 12.65% | 8.35% | 10.95% | 11.37% |
| CMS Energy Corporation | CMS | 4.30% | 0.70 | 12.65% | 8.35% | 10.19% | 10.80% |
| Duke Energy Corporation | DUK | 4.30% | 0.69 | 12.65% | 8.35% | 10.03% | 10.69% |
| Entergy Corporation | ETR | 4.30% | 0.76 | 12.65% | 8.35% | 10.68% | 11.17% |
| Evergy, Inc. | EVRG | 4.30% | 0.94 | 12.65% | 8.35% | 12.13% | 12.26% |
| IDACORP, Inc. | IDA | 4.30% | 0.74 | 12.65% | 8.35% | 10.49% | 11.03% |
| NextEra Energy, Inc. | NEE | 4.30% | 0.75 | 12.65% | 8.35% | 10.60% | 11.12% |
| NorthWestern Corporation | NWE | 4.30% | 0.76 | 12.65% | 8.35% | 10.68% | 11.17% |
| OGE Energy Corporation | OGE | 4.30% | 0.94 | 12.65% | 8.35% | 12.16% | 12.28% |
| Pinnacle West Capital Corporation | PNW | 4.30% | 0.75 | 12.65% | 8.35% | 10.60% | 11.12% |
| Portland General Electric Company | POR | 4.30% | 0.76 | 12.65% | 8.35% | 10.68% | 11.17% |
| Southern Company | SO | 4.30% | 0.68 | 12.65% | 8.35% | 10.00% | 10.66% |
| Xcel Energy Inc. | XEL | 4.30% | 0.67 | 12.65% | 8.35% | 9.92% | 10.60% |
| Mean | | | | | | 10.64% | 11.15% |
| Median | | | | | | 10.60% | 11.12% |

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, at 14.
[2] Source: LT Beta
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

Docket No. UE 433
Exhibit PAC/2206
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Long-Term Beta Coefficient**

**July 2024**

**HISTORICAL VALUE LINE BETA**

| Company | Ticker | [1] 12/31/2013 | [2] 12/31/2014 | [3] 12/31/2015 | [4] 12/31/2016 | [5] 12/31/2017 | [6] 12/31/2018 | [7] 12/31/2019 | [8] 12/31/2020 | [9] 12/31/2021 | [10] 12/31/2022 | [11] 12/31/2023 | [12] Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Alliant Energy Corporation | LNT | 0.75 | 0.80 | 0.80 | 0.70 | 0.70 | 0.60 | 0.60 | 0.85 | 0.85 | 0.85 | 0.90 | 0.76 |
| Ameren Corporation | AEE | 0.80 | 0.75 | 0.75 | 0.65 | 0.70 | 0.55 | 0.55 | 0.85 | 0.80 | 0.85 | 0.90 | 0.74 |
| American Electric Power Company, Inc. | AEP | 0.70 | 0.70 | 0.70 | 0.65 | 0.65 | 0.55 | 0.55 | 0.75 | 0.75 | 0.75 | 0.80 | 0.69 |
| Avista Corporation | AVA | 0.75 | 0.80 | 0.80 | 0.70 | 0.75 | 0.65 | 0.60 | 0.95 | 0.95 | 0.90 | 0.90 | 0.80 |
| CMS Energy Corporation | CMS | 0.70 | 0.70 | 0.75 | 0.65 | 0.65 | 0.55 | 0.50 | 0.80 | 0.80 | 0.80 | 0.85 | 0.70 |
| Duke Energy Corporation | DUK | 0.65 | 0.60 | 0.65 | 0.60 | 0.60 | 0.50 | 0.50 | 0.85 | 0.85 | 0.85 | 0.90 | 0.69 |
| Entergy Corporation | ETR | 0.70 | 0.70 | 0.70 | 0.65 | 0.65 | 0.60 | 0.60 | 0.95 | 0.95 | 0.95 | 0.95 | 0.76 |
| Evergy, Inc. | EVRG | | | | | | NMF | NMF | 1.00 | 0.95 | 0.90 | 0.90 | 0.94 |
| IDACORP, Inc. | IDA | 0.75 | 0.80 | 0.80 | 0.75 | 0.70 | 0.55 | 0.55 | 0.80 | 0.80 | 0.80 | 0.85 | 0.74 |
| NextEra Energy, Inc. | NEE | 0.70 | 0.70 | 0.75 | 0.65 | 0.65 | 0.55 | 0.55 | 0.90 | 0.90 | 0.95 | 1.00 | 0.75 |
| NorthWestern Corporation | NWE | 0.70 | 0.70 | 0.70 | 0.70 | 0.70 | 0.55 | 0.60 | 0.95 | 0.95 | 0.90 | 0.95 | 0.76 |
| OGE Energy Corporation | OGE | 0.85 | 0.90 | 0.95 | 0.90 | 0.95 | 0.85 | 0.75 | 1.10 | 1.05 | 1.00 | 1.05 | 0.94 |
| Pinnacle West Capital Corporation | PNW | 0.75 | 0.70 | 0.75 | 0.70 | 0.70 | 0.55 | 0.50 | 0.90 | 0.90 | 0.90 | 0.95 | 0.75 |
| Portland General Electric Company | POR | 0.75 | 0.80 | 0.80 | 0.70 | 0.70 | 0.60 | 0.55 | 0.85 | 0.90 | 0.85 | 0.90 | 0.76 |
| Southern Company | SO | 0.55 | 0.55 | 0.60 | 0.55 | 0.55 | 0.50 | 0.50 | 0.90 | 0.95 | 0.90 | 0.95 | 0.68 |
| Xcel Energy Inc. | XEL | 0.65 | 0.65 | 0.65 | 0.60 | 0.60 | 0.50 | 0.50 | 0.80 | 0.80 | 0.80 | 0.85 | 0.67 |
| Mean | | 0.72 | 0.72 | 0.74 | 0.68 | 0.68 | 0.58 | 0.56 | 0.89 | 0.88 | 0.87 | 0.91 | 0.76 |

Notes:
[1] Value Line, December 26, 2013
[2] Value Line, December 31, 2014
[3] Value Line, December 30, 2015
[4] Value Line, December 29, 2016
[5] Value Line, December 28, 2017
[6] Value Line, December 27, 2018
[7] Value Line, December 26, 2019
[8] Value Line, December 30, 2020
[9] Value Line, December 29, 2021
[10] Value Line, December 30, 2022
[11] Value Line, December 30, 2023
[12] Average ([1] - [11])

Docket No. UE 433
Exhibit PAC/2207
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Market Return**

**July 2024**

**MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX**

| | |
|---|---|
| [1] Estimate of the S&P 500 Dividend Yield | 1.58% |
| [2] Estimate of the S&P 500 Growth Rate | 10.99% |
| [3] S&P 500 Estimated Required Market Return | 12.65% |

| | | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] |
|---|---|---|---|---|---|---|---|---|---|
| Name | Ticker | Shares Outst'g | Price | Market Capitalization | Weight in Index | Estimated Dividend Yield | Cap-Weighted Dividend Yield | Bloomberg Long-Term Growth Est. | Cap-Weighted Long-Term Growth Est. |
| LyondellBasell Industries NV | LYB | 325.622 | 95.66 | 31,149.00 | 0.09% | 5.60% | 0.01% | 10.72% | 0.01% |
| American Express Co | AXP | 719.303 | 231.55 | 166,554.61 | 0.48% | 1.21% | 0.01% | 15.12% | 0.07% |
| Verizon Communications Inc | VZ | 4209.255 | 41.24 | 173,589.68 | 0.50% | 6.45% | 0.03% | 2.10% | 0.01% |
| Broadcom Inc | AVGO | 465.488 | 1605.53 | 747,354.95 | 2.14% | 1.31% | 0.03% | 15.86% | 0.34% |
| Boeing Co/The | BA | 613.884 | 182.01 | 111,733.03 | | | | 46.91% | |
| Solventum Corp | SOLV | 172.71 | 52.88 | 9,132.90 | | | | -2.00% | |
| Caterpillar Inc | CAT | 489.053 | 333.1 | 162,903.55 | 0.47% | 1.69% | 0.01% | 7.70% | 0.04% |
| JPMorgan Chase & Co | JPM | 2871.668 | 202.26 | 580,823.57 | 1.67% | 2.47% | 0.04% | 3.03% | 0.05% |
| Chevron Corp | CVX | 1847.32 | 156.42 | 288,957.79 | | 4.17% | | | |
| Coca-Cola Co/The | KO | 4307.955 | 63.65 | 274,201.34 | 0.79% | 3.05% | 0.02% | 6.36% | 0.05% |
| AbbVie Inc | ABBV | 1765.868 | 171.52 | 302,881.68 | 0.87% | 3.61% | 0.03% | 8.34% | 0.07% |
| Walt Disney Co/The | DIS | 1823.043 | 99.29 | 181,009.94 | | 0.91% | | 21.45% | |
| Corpay Inc | CPAY | 70.269 | 266.41 | 18,720.36 | 0.05% | | | 15.03% | 0.01% |
| Extra Space Storage Inc | EXR | 211.725 | 155.41 | 32,904.18 | 0.09% | 4.17% | 0.00% | 3.30% | 0.00% |
| Exxon Mobil Corp | XOM | 4485.928 | 115.12 | 516,420.03 | 1.48% | 3.30% | 0.05% | 6.00% | 0.09% |
| Phillips 66 | PSX | 423.952 | 141.17 | 59,849.30 | | 3.26% | | | |
| General Electric Co | GE | 1094.607 | 158.97 | 174,009.67 | | 0.70% | | 32.59% | |
| HP Inc | HPQ | 978.56 | 35.02 | 34,269.17 | 0.10% | 3.15% | 0.00% | 5.12% | 0.01% |
| Home Depot Inc/The | HD | 991.614 | 344.24 | 341,353.20 | 0.98% | 2.61% | 0.03% | 3.43% | 0.03% |
| Monolithic Power Systems Inc | MPWR | 48.672 | 821.68 | 39,992.81 | 0.11% | 0.61% | 0.00% | 18.00% | 0.02% |
| International Business Machines Corp | IBM | 918.603 | 172.95 | 158,872.39 | 0.46% | 3.86% | 0.02% | 3.19% | 0.01% |
| Johnson & Johnson | JNJ | 2406.679 | 146.16 | 351,760.20 | 1.01% | 3.39% | 0.03% | 4.99% | 0.05% |
| Lululemon Athletica Inc | LULU | 119.886 | 298.7 | 35,809.95 | 0.10% | | | 7.00% | 0.01% |
| McDonald's Corp | MCD | 720.682 | 254.84 | 183,658.60 | 0.53% | 2.62% | 0.01% | 7.51% | 0.04% |
| Merck & Co Inc | MRK | 2532.806 | 123.8 | 313,561.38 | 0.90% | 2.49% | 0.02% | 11.00% | 0.10% |
| 3M Co | MMM | 553.361 | 102.19 | 56,547.96 | | 2.74% | | -7.15% | |
| American Water Works Co Inc | AWK | 194.823 | 129.16 | 25,163.34 | 0.07% | 2.37% | 0.00% | 8.00% | 0.01% |
| Bank of America Corp | BAC | 7820.37 | 39.77 | 311,016.11 | | 2.41% | | -6.00% | |
| Pfizer Inc | PFE | 5666.593 | 27.98 | 158,551.27 | 0.45% | 6.00% | 0.03% | 7.72% | 0.04% |
| Procter & Gamble Co/The | PG | 2360.135 | 164.92 | 389,233.46 | 1.12% | 2.44% | 0.03% | 8.09% | 0.09% |
| AT&T Inc | T | 7170.165 | 19.11 | 137,021.85 | 0.39% | 5.81% | 0.02% | 1.63% | 0.01% |
| Travelers Cos Inc/The | TRV | 228.993 | 203.34 | 46,563.44 | 0.13% | 2.07% | 0.00% | 18.24% | 0.02% |
| RTX Corp | RTX | 1329.506 | 100.39 | 133,469.11 | 0.38% | 2.51% | 0.01% | 10.62% | 0.04% |
| Analog Devices Inc | ADI | 496.217 | 228.26 | 113,266.49 | | 1.61% | | -2.75% | |
| Walmart Inc | WMT | 8043.543 | 67.71 | 544,628.30 | 1.56% | 1.23% | 0.02% | 8.23% | 0.13% |
| Cisco Systems Inc | CSCO | 4049.187 | 47.51 | 192,376.87 | | 3.37% | | -0.09% | |
| Intel Corp | INTC | 4256.872 | 30.97 | 131,835.33 | 0.38% | 1.61% | 0.01% | 11.40% | 0.04% |
| General Motors Co | GM | 1140.395 | 46.46 | 52,982.75 | 0.15% | 1.03% | 0.00% | 16.07% | 0.02% |
| Microsoft Corp | MSFT | 7432.306 | 446.95 | 3,321,869.17 | 9.53% | 0.67% | 0.06% | 14.81% | 1.41% |
| Dollar General Corp | DG | 219.895 | 132.23 | 29,076.72 | | 1.78% | | -1.92% | |
| Cigna Group/The | CI | 284.074 | 330.57 | 93,906.34 | 0.27% | 1.69% | 0.00% | 11.65% | 0.03% |
| Kinder Morgan Inc | KMI | 2219.384 | 19.87 | 44,099.16 | 0.13% | 5.79% | 0.01% | 5.86% | 0.01% |
| Citigroup Inc | C | 1907.44 | 63.46 | 121,046.14 | | 3.34% | | 27.67% | |
| American International Group Inc | AIG | 663.668 | 74.24 | 49,270.71 | 0.14% | 2.16% | 0.00% | 14.09% | 0.02% |
| Altria Group Inc | MO | 1717.626 | 45.55 | 78,237.86 | 0.22% | 8.61% | 0.02% | 3.89% | 0.01% |
| HCA Healthcare Inc | HCA | 261.914 | 321.28 | 84,147.73 | 0.24% | 0.82% | 0.00% | 9.57% | 0.02% |
| International Paper Co | IP | 347.332 | 43.15 | 14,987.38 | | 4.29% | | -2.00% | |
| Hewlett Packard Enterprise Co | HPE | 1299.673 | 21.17 | 27,514.08 | 0.08% | 2.46% | 0.00% | 3.73% | 0.00% |
| Abbott Laboratories | ABT | 1739.634 | 103.91 | 180,765.37 | 0.52% | 2.12% | 0.01% | 8.00% | 0.04% |
| Aflac Inc | AFL | 568.222 | 89.31 | 50,747.91 | 0.15% | 2.24% | 0.00% | 7.55% | 0.01% |
| Air Products and Chemicals Inc | APD | 222.306 | 256.28 | 56,972.58 | 0.16% | 2.76% | 0.00% | 9.63% | 0.02% |
| Super Micro Computer Inc | SMCI | 58.557 | 819.35 | 47,978.68 | | | | 53.18% | |
| Royal Caribbean Cruises Ltd | RCL | 257.349 | 159.43 | 41,029.15 | | | | 29.92% | |
| Hess Corp | HES | 308.109 | 147.52 | 45,452.24 | 0.13% | 1.19% | 0.00% | 18.00% | 0.02% |
| Archer-Daniels-Midland Co | ADM | 494.438 | 60.45 | 29,888.78 | | 3.31% | | -2.85% | |
| Automatic Data Processing Inc | ADP | 409.291 | 238.69 | 97,693.67 | 0.28% | 2.35% | 0.01% | 11.31% | 0.03% |
| Verisk Analytics Inc | VRSK | 142.675 | 269.55 | 38,458.05 | 0.11% | 0.58% | 0.00% | 11.71% | 0.01% |
| AutoZone Inc | AZO | 17.083 | 2964.1 | 50,635.72 | 0.15% | | | 14.66% | 0.02% |
| Linde PLC | LIN | 480.676 | 438.81 | 210,925.44 | 0.60% | 1.27% | 0.01% | 11.82% | 0.07% |
| Avery Dennison Corp | AVY | 80.553 | 218.65 | 17,612.91 | 0.05% | 1.61% | 0.00% | 11.67% | 0.01% |
| Enphase Energy Inc | ENPH | 136.063 | 99.71 | 13,566.84 | 0.04% | | | 18.17% | 0.01% |
| MSCI Inc | MSCI | 79.224 | 481.75 | 38,166.16 | 0.11% | 1.33% | 0.00% | 11.58% | 0.01% |
| Ball Corp | BALL | 310.378 | 60.02 | 18,628.89 | 0.05% | 1.33% | 0.00% | 12.89% | 0.01% |
| Axon Enterprise Inc | AXON | 75.467 | 294.24 | 22,205.41 | | | | | |
| Dayforce Inc | DAY | 155.562 | 49.6 | 7,715.88 | | | | | |
| Carrier Global Corp | CARR | 901.012 | 63.08 | 56,835.84 | 0.16% | 1.20% | 0.00% | 7.87% | 0.01% |
| Bank of New York Mellon Corp/The | BK | 747.816 | 59.89 | 44,786.70 | 0.13% | 2.81% | 0.00% | 10.01% | 0.01% |
| Otis Worldwide Corp | OTIS | 404.323 | 96.26 | 38,920.13 | 0.11% | 1.62% | 0.00% | 9.00% | 0.01% |
| Baxter International Inc | BAX | 509.58 | 33.45 | 17,045.45 | 0.05% | 3.47% | 0.00% | 9.78% | 0.00% |
| Becton Dickinson & Co | BDX | 289.006 | 233.71 | 67,543.59 | 0.19% | 1.63% | 0.00% | 7.77% | 0.02% |
| Berkshire Hathaway Inc | BRK/B | 1311.385 | 406.8 | 533,471.42 | | | | | |
| Best Buy Co Inc | BBY | 215.714 | 84.29 | 18,182.53 | | 4.46% | | -0.43% | |
| Boston Scientific Corp | BSX | 1470.18 | 77.01 | 113,218.56 | 0.32% | | | 12.08% | 0.04% |
| Bristol-Myers Squibb Co | BMY | 2027.1 | 41.53 | 84,185.46 | | 5.78% | | -4.12% | |
| Brown-Forman Corp | BF/B | 305.537 | 43.19 | 13,196.14 | | 2.02% | | -1.26% | |
| Coterra Energy Inc | CTRA | 744.233 | 26.67 | 19,848.69 | 0.06% | 3.15% | 0.00% | 10.79% | 0.01% |
| Campbell Soup Co | CPB | 298.554 | 45.19 | 13,491.66 | 0.04% | 3.28% | 0.00% | 8.14% | 0.00% |
| Hilton Worldwide Holdings Inc | HLT | 250.046 | 218.2 | 54,560.04 | 0.16% | 0.27% | 0.00% | 15.52% | 0.02% |
| Carnival Corp | CCL | 1122.32 | 18.72 | 21,009.83 | | | | | |
| Qorvo Inc | QRVO | 95.629 | 116.04 | 11,096.79 | | | | 20.04% | |
| Builders FirstSource Inc | BLDR | 122.057 | 138.41 | 16,893.91 | 0.05% | | | 4.81% | 0.00% |
| UDR Inc | UDR | 329.307 | 41.15 | 13,550.98 | 0.04% | 4.13% | 0.00% | 1.85% | 0.00% |
| Clorox Co/The | CLX | 124.188 | 136.47 | 16,947.94 | 0.05% | 3.52% | 0.00% | 15.46% | 0.01% |
| Paycom Software Inc | PAYC | 58.11 | 143.04 | 8,312.05 | 0.02% | 1.05% | 0.00% | 6.00% | 0.00% |
| CMS Energy Corp | CMS | 298.635 | 59.53 | 17,777.74 | 0.05% | 3.46% | 0.00% | 7.75% | 0.00% |

| Name | Ticker | [4] Shares Outst'g | [5] Price | [6] Market Capitalization | [7] Weight in Index | [8] Estimated Dividend Yield | [9] Cap-Weighted Dividend Yield | [10] Bloomberg Long-Term Growth Est. | [11] Cap-Weighted Long-Term Growth Est. |
|---|---|---|---|---|---|---|---|---|---|
| Colgate-Palmolive Co | CL | 820.441 | 97.04 | 79,615.59 | 0.23% | 2.06% | 0.00% | 8.36% | 0.02% |
| EPAM Systems Inc | EPAM | 57.974 | 188.11 | 10,905.49 | 0.03% | | | 5.54% | 0.00% |
| Conagra Brands Inc | CAG | 478.063 | 28.42 | 13,586.55 | 0.04% | 4.93% | 0.00% | 1.58% | 0.00% |
| Airbnb Inc | ABNB | 441.5 | 151.63 | 66,944.65 | | | | 20.22% | |
| Consolidated Edison Inc | ED | 344.924 | 89.42 | 30,843.10 | 0.09% | 3.71% | 0.00% | 5.70% | 0.01% |
| Corning Inc | GLW | 856.619 | 38.85 | 33,279.65 | 0.10% | 2.88% | 0.00% | 12.03% | 0.01% |
| GoDaddy Inc | GDDY | 140.941 | 139.71 | 19,690.87 | | | | | |
| Cummins Inc | CMI | 136.78 | 276.93 | 37,878.49 | 0.11% | 2.43% | 0.00% | 7.56% | 0.01% |
| Caesars Entertainment Inc | CZR | 216.416 | 39.74 | 8,600.37 | | | | -32.44% | |
| Danaher Corp | DHR | 740.687 | 249.85 | 185,060.65 | 0.53% | 0.43% | 0.00% | 3.84% | 0.02% |
| Target Corp | TGT | 462.637 | 148.04 | 68,488.78 | 0.20% | 3.03% | 0.01% | 13.97% | 0.03% |
| Deere & Co | DE | 275.57 | 373.63 | 102,961.22 | | 1.57% | | -6.84% | |
| Dominion Energy Inc | D | 837.593 | 49 | 41,042.06 | 0.12% | 5.45% | 0.01% | 11.59% | 0.01% |
| Dover Corp | DOV | 137.43 | 180.45 | 24,799.24 | 0.07% | 1.13% | 0.00% | 7.56% | 0.01% |
| Alliant Energy Corp | LNT | 256.379 | 50.9 | 13,049.69 | 0.04% | 3.77% | 0.00% | 6.00% | 0.00% |
| Steel Dynamics Inc | STLD | 157.133 | 129.5 | 20,348.72 | | 1.42% | | -4.60% | |
| Duke Energy Corp | DUK | 771 | 100.23 | 77,277.33 | 0.22% | 4.09% | 0.01% | 6.20% | 0.01% |
| Regency Centers Corp | REG | 184.581 | 62.2 | 11,480.94 | 0.03% | 4.31% | 0.00% | 3.27% | 0.00% |
| Eaton Corp PLC | ETN | 399.892 | 313.55 | 125,386.14 | 0.36% | 1.20% | 0.00% | 13.83% | 0.05% |
| Ecolab Inc | ECL | 285.57 | 238 | 67,965.66 | 0.19% | 0.96% | 0.00% | 14.16% | 0.03% |
| Revvity Inc | RVTY | 123.393 | 104.86 | 12,938.99 | 0.04% | 0.27% | 0.00% | 8.26% | 0.00% |
| Emerson Electric Co | EMR | 572.1 | 110.16 | 63,022.54 | 0.18% | 1.91% | 0.00% | 15.07% | 0.03% |
| EOG Resources Inc | EOG | 574.711 | 125.87 | 72,338.87 | 0.21% | 2.89% | 0.01% | 5.99% | 0.01% |
| Aon PLC | AON | 217.431 | 293.58 | 63,833.39 | 0.18% | 0.92% | 0.00% | 10.38% | 0.02% |
| Entergy Corp | ETR | 213.273 | 107 | 22,820.21 | 0.07% | 4.22% | 0.00% | 6.64% | 0.00% |
| Equifax Inc | EFX | 123.611 | 242.46 | 29,970.72 | 0.09% | 0.64% | 0.00% | 15.31% | 0.01% |
| EQT Corp | EQT | 441.593 | 36.98 | 16,330.11 | | 1.70% | | | |
| IQVIA Holdings Inc | IQV | 182.2 | 211.44 | 38,524.37 | 0.11% | | | 10.44% | 0.01% |
| Gartner Inc | IT | 77.63 | 449.06 | 34,860.53 | 0.10% | | | 9.89% | 0.01% |
| FedEx Corp | FDX | 245.524 | 299.84 | 73,617.92 | 0.21% | 1.84% | 0.00% | 13.35% | 0.03% |
| FMC Corp | FMC | 124.818 | 57.55 | 7,183.28 | 0.02% | 4.03% | 0.00% | 18.88% | 0.00% |
| Brown & Brown Inc | BRO | 285.249 | 89.41 | 25,504.11 | 0.07% | 0.58% | 0.00% | 9.77% | 0.01% |
| Ford Motor Co | F | 3921.485 | 12.54 | 49,175.42 | 0.14% | 4.78% | 0.01% | 1.67% | 0.00% |
| NextEra Energy Inc | NEE | 2055 | 70.81 | 145,514.55 | 0.42% | 2.91% | 0.01% | 9.59% | 0.04% |
| Franklin Resources Inc | BEN | 526.091 | 22.35 | 11,758.13 | | 5.55% | | | |
| Garmin Ltd | GRMN | 192.078 | 162.92 | 31,293.35 | 0.09% | 1.84% | 0.00% | 8.04% | 0.01% |
| Freeport-McMoRan Inc | FCX | 1436.49 | 48.6 | 69,813.41 | 0.20% | 1.23% | 0.00% | 17.27% | 0.03% |
| Dexcom Inc | DXCM | 397.684 | 113.38 | 45,089.41 | | | | 23.63% | |
| General Dynamics Corp | GD | 274.364 | 290.14 | 79,603.97 | 0.23% | 1.96% | 0.00% | 14.18% | 0.03% |
| General Mills Inc | GIS | 558.146 | 63.26 | 35,308.32 | 0.10% | 3.79% | 0.00% | 1.19% | 0.00% |
| Genuine Parts Co | GPC | 139.299 | 138.32 | 19,267.84 | | 2.89% | | | |
| Atmos Energy Corp | ATO | 150.877 | 116.65 | 17,599.80 | 0.05% | 2.76% | 0.00% | 7.00% | 0.00% |
| WW Grainger Inc | GWW | 49.069 | 902.24 | 44,272.01 | | 0.91% | | | |
| Halliburton Co | HAL | 885.301 | 33.78 | 29,905.47 | 0.09% | 2.01% | 0.00% | 10.30% | 0.01% |
| L3Harris Technologies Inc | LHX | 189.68 | 224.58 | 42,598.33 | 0.12% | 2.07% | 0.00% | 8.53% | 0.01% |
| Healthpeak Properties Inc | DOC | 703.782 | 19.6 | 13,794.13 | 0.04% | 6.12% | 0.00% | 4.48% | 0.00% |
| Insulet Corp | PODD | 70.04 | 201.8 | 14,134.07 | | | | 28.44% | |
| Catalent Inc | CTLT | 180.98 | 56.23 | 10,176.51 | | | | 28.24% | |
| Fortive Corp | FTV | 352.029 | 74.1 | 26,085.35 | 0.07% | 0.43% | 0.00% | 8.98% | 0.01% |
| Hershey Co/The | HSY | 147.616 | 183.83 | 27,136.25 | 0.08% | 2.98% | 0.00% | 2.36% | 0.00% |
| Synchrony Financial | SYF | 401.544 | 47.19 | 18,948.86 | | 2.12% | | | |
| Hormel Foods Corp | HRL | 548.305 | 30.49 | 16,717.82 | 0.05% | 3.71% | 0.00% | 6.59% | 0.00% |
| Arthur J Gallagher & Co | AJG | 218.5 | 259.31 | 56,659.24 | 0.16% | 0.93% | 0.00% | 12.55% | 0.02% |
| Mondelez International Inc | MDLZ | 1341.359 | 65.44 | 87,778.53 | 0.25% | 2.60% | 0.01% | 7.65% | 0.02% |
| CenterPoint Energy Inc | CNP | 639.724 | 30.98 | 19,818.65 | 0.06% | 2.58% | 0.00% | 7.95% | 0.00% |
| Humana Inc | HUM | 120.501 | 373.65 | 45,025.20 | | 0.95% | | -1.30% | |
| Willis Towers Watson PLC | WTW | 102.236 | 262.14 | 26,800.15 | 0.08% | 1.34% | 0.00% | 12.41% | 0.01% |
| Illinois Tool Works Inc | ITW | 298.4 | 236.96 | 70,708.86 | 0.20% | 2.36% | 0.00% | 7.26% | 0.01% |
| CDW Corp/DE | CDW | 134.398 | 223.84 | 30,083.65 | 0.09% | 1.11% | 0.00% | 7.02% | 0.01% |
| Trane Technologies PLC | TT | 226.352 | 328.93 | 74,453.96 | 0.21% | 1.02% | 0.00% | 13.47% | 0.03% |
| Interpublic Group of Cos Inc/The | IPG | 377.424 | 29.09 | 10,979.26 | 0.03% | 4.54% | 0.00% | 3.36% | 0.00% |
| International Flavors & Fragrances Inc | IFF | 255.351 | 95.21 | 24,311.97 | 0.07% | 1.68% | 0.00% | 0.23% | 0.00% |
| Generac Holdings Inc | GNRC | 60.614 | 132.22 | 8,014.38 | 0.02% | | | 7.00% | 0.00% |
| NXP Semiconductors NV | NXPI | 255.684 | 269.09 | 68,802.01 | 0.20% | 1.51% | 0.00% | 6.92% | 0.01% |
| Kellanova | K | 341.884 | 57.68 | 19,719.87 | 0.06% | 3.88% | 0.00% | 8.42% | 0.00% |
| Broadridge Financial Solutions Inc | BR | 118.18 | 197 | 23,281.46 | | 1.62% | | | |
| Kimberly-Clark Corp | KMB | 336.709 | 138.2 | 46,533.18 | 0.13% | 3.53% | 0.00% | 9.18% | 0.01% |
| Kimco Realty Corp | KIM | 674.116 | 19.46 | 13,118.30 | 0.04% | 4.93% | 0.00% | 3.25% | 0.00% |
| Oracle Corp | ORCL | 2755.86 | 141.2 | 389,127.43 | 1.12% | 1.13% | 0.01% | 15.06% | 0.17% |
| Kroger Co/The | KR | 721.791 | 49.93 | 36,039.02 | 0.10% | 2.56% | 0.00% | 3.11% | 0.00% |
| Lennar Corp | LEN | 241.703 | 149.87 | 36,224.03 | 0.10% | 1.33% | 0.00% | 4.30% | 0.00% |
| Eli Lilly & Co | LLY | 950.405 | 905.38 | 860,477.68 | | 0.57% | | 40.01% | |
| Bath & Body Works Inc | BBWI | 223.231 | 39.05 | 8,717.17 | 0.02% | 2.05% | 0.00% | 13.41% | 0.00% |
| Charter Communications Inc | CHTR | 144.386 | 298.96 | 43,165.64 | 0.12% | | | 5.00% | 0.01% |
| Loews Corp | L | 221.406 | 74.74 | 16,547.88 | | 0.33% | | | |
| Lowe's Cos Inc | LOW | 569.835 | 220.46 | 125,625.82 | 0.36% | 2.09% | 0.01% | 4.03% | 0.01% |
| Hubbell Inc | HUBB | 53.686 | 365.48 | 19,621.16 | 0.06% | 1.34% | 0.00% | 18.00% | 0.01% |
| IDEX Corp | IEX | 75.695 | 201.2 | 15,229.83 | | 1.37% | | | |
| Marsh & McLennan Cos Inc | MMC | 492.724 | 210.72 | 103,826.80 | 0.30% | 1.35% | 0.00% | 8.12% | 0.02% |
| Masco Corp | MAS | 220.244 | 66.67 | 14,683.67 | 0.04% | 1.74% | 0.00% | 8.64% | 0.00% |
| S&P Global Inc | SPGI | 320.257 | 446 | 142,834.62 | 0.41% | 0.82% | 0.00% | 13.11% | 0.05% |
| Medtronic PLC | MDT | 1282.27 | 78.71 | 100,927.47 | 0.29% | 3.56% | 0.01% | 5.61% | 0.02% |
| Viatris Inc | VTRS | 1190.676 | 10.63 | 12,656.89 | | 4.52% | | -2.57% | |
| CVS Health Corp | CVS | 1255.373 | 59.06 | 74,142.33 | 0.21% | 4.50% | 0.01% | 4.01% | 0.01% |
| DuPont de Nemours Inc | DD | 418.104 | 80.49 | 33,653.19 | 0.10% | 1.89% | 0.00% | 1.03% | 0.00% |
| Micron Technology Inc | MU | 1108.841 | 131.53 | 145,845.86 | | 0.35% | | 31.94% | |
| Motorola Solutions Inc | MSI | 166.787 | 386.05 | 64,388.12 | 0.18% | 1.02% | 0.00% | 8.89% | 0.02% |
| Cboe Global Markets Inc | CBOE | 105.154 | 170.06 | 17,882.49 | 0.05% | 1.29% | 0.00% | 14.28% | 0.01% |
| Newmont Corp | NEM | 1153.163 | 41.87 | 48,282.93 | | 2.39% | | 47.89% | |
| NIKE Inc | NKE | 1211.462 | 75.37 | 91,307.89 | 0.26% | 1.96% | 0.01% | 4.46% | 0.01% |
| NiSource Inc | NI | 448.305 | 28.81 | 12,915.67 | 0.04% | 3.68% | 0.00% | 7.00% | 0.00% |
| Norfolk Southern Corp | NSC | 225.914 | 214.69 | 48,501.48 | 0.14% | 2.52% | 0.00% | 9.42% | 0.01% |
| Principal Financial Group Inc | PFG | 234.384 | 78.45 | 18,387.42 | 0.05% | 3.62% | 0.00% | 12.40% | 0.01% |
| Eversource Energy | ES | 350.727 | 56.71 | 19,889.73 | 0.06% | 5.04% | 0.00% | 5.23% | 0.00% |

| Name | Ticker | [4] Shares Outst'g | [5] Price | [6] Market Capitalization | [7] Weight in Index | [8] Estimated Dividend Yield | [9] Cap-Weighted Dividend Yield | [10] Bloomberg Long-Term Growth Est. | [11] Cap-Weighted Long-Term Growth Est. |
|---|---|---|---|---|---|---|---|---|---|
| Northrop Grumman Corp | NOC | 147.99 | 435.95 | 64,516.24 | 0.19% | 1.89% | 0.00% | 18.34% | 0.03% |
| Wells Fargo & Co | WFC | 3486.315 | 59.39 | 207,052.25 | 0.59% | 2.36% | 0.01% | 8.79% | 0.05% |
| Nucor Corp | NUE | 239.762 | 158.08 | 37,901.58 | | 1.37% | | -1.29% | |
| Occidental Petroleum Corp | OXY | 886.637 | 63.03 | 55,884.73 | 0.16% | 1.40% | 0.00% | 20.00% | 0.03% |
| Omnicom Group Inc | OMC | 195.834 | 89.7 | 17,566.31 | 0.05% | 3.12% | 0.00% | 7.48% | 0.00% |
| ONEOK Inc | OKE | 583.647 | 81.55 | 47,596.41 | 0.14% | 4.86% | 0.01% | 2.55% | 0.00% |
| Raymond James Financial Inc | RJF | 207.277 | 123.1601 | 25,528.26 | 0.07% | 1.46% | 0.00% | 15.38% | 0.01% |
| PG&E Corp | PCG | 2133.508 | 17.46 | 37,251.05 | 0.11% | 0.23% | 0.00% | 9.95% | 0.01% |
| Parker-Hannifin Corp | PH | 128.541 | 505.81 | 65,017.32 | 0.19% | 1.29% | 0.00% | 13.84% | 0.03% |
| Rollins Inc | ROL | 484.23 | 48.79 | 23,625.58 | 0.07% | 1.23% | 0.00% | 13.04% | 0.01% |
| PPL Corp | PPL | 737.124 | 27.65 | 20,381.48 | 0.06% | 3.73% | 0.00% | 7.67% | 0.00% |
| ConocoPhillips | COP | 1169.534 | 114.38 | 133,771.30 | 0.38% | 2.73% | 0.01% | 9.00% | 0.03% |
| PulteGroup Inc | PHM | 210.342 | 110.1 | 23,158.65 | 0.07% | 0.73% | 0.00% | 7.65% | 0.01% |
| Pinnacle West Capital Corp | PNW | 113.557 | 76.38 | 8,673.48 | 0.02% | 4.61% | 0.00% | 6.67% | 0.00% |
| PNC Financial Services Group Inc/The | PNC | 397.907 | 155.48 | 61,866.58 | | 3.99% | | 31.00% | |
| PPG Industries Inc | PPG | 235.361 | 125.89 | 29,629.60 | 0.08% | 2.07% | 0.00% | 8.03% | 0.01% |
| Progressive Corp/The | PGR | 585.698 | 207.71 | 121,655.33 | | 0.19% | | 33.41% | |
| Veralto Corp | VLTO | 246.847 | 95.47 | 23,566.48 | | 0.38% | | | |
| Public Service Enterprise Group Inc | PEG | 498.587 | 73.7 | 36,745.86 | 0.11% | 3.26% | 0.00% | 6.28% | 0.01% |
| Cooper Cos Inc/The | COO | 199.12 | 87.3 | 17,383.18 | 0.05% | | | 10.00% | 0.00% |
| Edison International | EIX | 383.925 | 71.81 | 27,569.65 | 0.08% | 4.34% | 0.00% | 7.30% | 0.01% |
| Schlumberger NV | SLB | 1429.338 | 47.18 | 67,436.17 | 0.19% | 2.33% | 0.00% | 12.91% | 0.02% |
| Charles Schwab Corp/The | SCHW | 1777.281 | 73.69 | 130,967.84 | 0.38% | 1.36% | 0.01% | 14.20% | 0.05% |
| Sherwin-Williams Co/The | SHW | 253.549 | 298.43 | 75,666.63 | 0.22% | 0.96% | 0.00% | 9.56% | 0.02% |
| West Pharmaceutical Services Inc | WST | 72.843 | 329.39 | 23,993.76 | 0.07% | 0.24% | 0.00% | 7.72% | 0.01% |
| J M Smucker Co/The | SJM | 106.433 | 109.04 | 11,605.45 | 0.03% | 3.89% | 0.00% | 6.52% | 0.00% |
| Snap-on Inc | SNA | 52.719 | 261.39 | 13,780.22 | 0.04% | 2.85% | 0.00% | 3.83% | 0.00% |
| AMETEK Inc | AME | 231.47 | 166.71 | 38,588.36 | 0.11% | 0.67% | 0.00% | 7.43% | 0.01% |
| Uber Technologies Inc | UBER | 2089.52 | 72.68 | 151,866.31 | | | | 61.05% | |
| Southern Co/The | SO | 1094.633 | 77.57 | 84,910.68 | 0.24% | 3.71% | 0.01% | 6.15% | 0.01% |
| Truist Financial Corp | TFC | 1338.096 | 38.85 | 51,985.03 | 0.15% | 5.35% | 0.01% | 10.51% | 0.02% |
| Southwest Airlines Co | LUV | 598.456 | 28.61 | 17,121.83 | | 2.52% | | | |
| W R Berkley Corp | WRB | 255.662 | 78.58 | 20,089.92 | 0.06% | 0.61% | 0.00% | 13.64% | 0.01% |
| Stanley Black & Decker Inc | SWK | 153.879 | 79.89 | 12,293.39 | 0.04% | 4.06% | 0.00% | 7.00% | 0.00% |
| Public Storage | PSA | 175.829 | 287.65 | 50,577.21 | 0.15% | 4.17% | 0.01% | 3.07% | 0.00% |
| Arista Networks Inc | ANET | 313.363 | 350.48 | 109,827.46 | 0.31% | | | 13.58% | 0.04% |
| Sysco Corp | SYY | 497.982 | 71.39 | 35,550.93 | 0.10% | 2.86% | 0.00% | 13.00% | 0.01% |
| Corteva Inc | CTVA | 687.797 | 53.94 | 37,099.77 | 0.11% | 1.19% | 0.00% | 11.33% | 0.01% |
| Texas Instruments Inc | TXN | 910.482 | 194.53 | 177,116.06 | | 2.67% | | -1.14% | |
| Textron Inc | TXT | 190.699 | 85.86 | 16,373.42 | 0.05% | 0.09% | 0.00% | 10.05% | 0.00% |
| Thermo Fisher Scientific Inc | TMO | 381.716 | 553 | 211,088.95 | 0.61% | 0.28% | 0.00% | 7.40% | 0.04% |
| TJX Cos Inc/The | TJX | 1130.149 | 110.1 | 124,429.40 | 0.36% | 1.36% | 0.00% | 8.13% | 0.03% |
| Globe Life Inc | GL | 92.27 | 82.28 | 7,591.98 | 0.02% | 1.17% | 0.00% | 7.00% | 0.00% |
| Johnson Controls International plc | JCI | 673.676 | 66.47 | 44,779.24 | 0.13% | 2.23% | 0.00% | 9.45% | 0.01% |
| Ulta Beauty Inc | ULTA | 47.716 | 385.87 | 18,412.17 | 0.05% | | | 6.46% | 0.00% |
| Union Pacific Corp | UNP | 610.122 | 226.26 | 138,046.20 | 0.40% | 2.30% | 0.01% | 11.49% | 0.05% |
| Keysight Technologies Inc | KEYS | 174.539 | 136.75 | 23,868.21 | | | | -3.55% | |
| UnitedHealth Group Inc | UNH | 920.385 | 509.26 | 468,715.27 | 1.34% | 1.65% | 0.02% | 9.94% | 0.13% |
| Blackstone Inc | BX | 714.646 | 123.8 | 88,473.17 | | 2.68% | | 23.93% | |
| Marathon Oil Corp | MRO | 564.036 | 28.67 | 16,170.91 | | 1.53% | | | |
| Bio-Rad Laboratories Inc | BIO | 23.446 | 273.11 | 6,403.34 | | | | | |
| Ventas Inc | VTR | 404.774 | 50.81 | 20,566.57 | 0.06% | 3.54% | 0.00% | 6.19% | 0.00% |
| Labcorp Holdings Inc | LH | 84.294 | 203.51 | 17,154.67 | 0.05% | 1.42% | 0.00% | 9.46% | 0.00% |
| Vulcan Materials Co | VMC | 132.252 | 248.68 | 32,888.43 | 0.09% | 0.74% | 0.00% | 15.71% | 0.01% |
| Weyerhaeuser Co | WY | 729.617 | 28.39 | 20,713.83 | | 2.82% | | -0.33% | |
| Williams Cos Inc/The | WMB | 1218.754 | 42.5 | 51,797.05 | 0.15% | 4.47% | 0.01% | 3.94% | 0.01% |
| Constellation Energy Corp | CEG | 315.121 | 200.27 | 63,109.28 | 0.18% | 0.70% | 0.00% | 14.59% | 0.03% |
| WEC Energy Group Inc | WEC | 315.823 | 78.46 | 24,779.47 | 0.07% | 4.26% | 0.00% | 6.85% | 0.00% |
| Adobe Inc | ADBE | 443.4 | 555.54 | 246,326.44 | 0.71% | | | 16.27% | 0.11% |
| Vistra Corp | VST | 347.46 | 85.98 | 29,874.61 | | 1.01% | | | |
| AES Corp/The | AES | 710.667 | 17.57 | 12,486.42 | | 3.93% | | | |
| Expeditors International of Washington Inc | EXPD | 141.252 | 124.79 | 17,626.84 | 0.05% | 1.17% | 0.00% | 4.39% | 0.00% |
| Amgen Inc | AMGN | 536.435 | 312.45 | 167,609.12 | 0.48% | 2.88% | 0.01% | 6.22% | 0.03% |
| Apple Inc | AAPL | 15334.082 | 210.62 | 3,229,664.35 | 9.26% | 0.47% | 0.04% | 12.73% | 1.18% |
| Autodesk Inc | ADSK | 215.509 | 247.45 | 53,327.70 | 0.15% | | | 9.94% | 0.02% |
| Cintas Corp | CTAS | 101.463 | 700.26 | 71,050.48 | 0.20% | 0.77% | 0.00% | 12.04% | 0.02% |
| Comcast Corp | CMCSA | 3914.182 | 39.16 | 153,279.37 | 0.44% | 3.17% | 0.01% | 8.33% | 0.04% |
| Molson Coors Beverage Co | TAP | 197.551 | 50.83 | 10,041.52 | 0.03% | 3.46% | 0.00% | 4.65% | 0.00% |
| KLA Corp | KLAC | 134.64 | 824.51 | 111,012.03 | 0.32% | 0.70% | 0.00% | 8.99% | 0.03% |
| Marriott International Inc/MD | MAR | 285.622 | 241.77 | 69,054.83 | 0.20% | 1.04% | 0.00% | 5.56% | 0.01% |
| Fiserv Inc | FI | 585.102 | 149.04 | 87,203.60 | 0.25% | | | 11.74% | 0.03% |
| McCormick & Co Inc/MD | MKC | 252.015 | 70.94 | 17,877.94 | 0.05% | 2.37% | 0.00% | 5.83% | 0.00% |
| PACCAR Inc | PCAR | 524.145 | 102.94 | 53,955.49 | | 1.17% | | -2.16% | |
| Costco Wholesale Corp | COST | 443.335 | 849.99 | 376,830.32 | 1.08% | 0.55% | 0.01% | 9.64% | 0.10% |
| Stryker Corp | SYK | 380.95 | 340.25 | 129,618.24 | 0.37% | 0.94% | 0.00% | 8.39% | 0.03% |
| Tyson Foods Inc | TSN | 286.016 | 57.14 | 16,342.95 | | 3.43% | | 53.92% | |
| Lamb Weston Holdings Inc | LW | 144.391 | 84.08 | 12,140.40 | 0.03% | 1.71% | 0.00% | 11.00% | 0.00% |
| Applied Materials Inc | AMAT | 827.975 | 235.99 | 195,393.82 | 0.56% | 0.68% | 0.00% | 15.06% | 0.08% |
| American Airlines Group Inc | AAL | 653.541 | 11.33 | 7,404.62 | | | | -4.75% | |
| Cardinal Health Inc | CAH | 243.567 | 97.8144 | 23,824.36 | 0.07% | 2.07% | 0.00% | 11.98% | 0.01% |
| Cincinnati Financial Corp | CINF | 156.558 | 118.1 | 18,489.50 | 0.05% | 2.74% | 0.00% | 7.33% | 0.00% |
| Paramount Global | PARA | 625.776 | 10.39 | 6,501.81 | | 1.92% | | 45.42% | |
| DR Horton Inc | DHI | 329.312 | 140.93 | 46,409.94 | 0.13% | 0.85% | 0.00% | 4.37% | 0.01% |
| Electronic Arts Inc | EA | 265.735 | 139.33 | 37,024.86 | 0.11% | 0.55% | 0.00% | 12.24% | 0.01% |
| Fair Isaac Corp | FICO | 24.711 | 1488.66 | 36,786.28 | | | | | |
| Fastenal Co | FAST | 572.427 | 62.84 | 35,971.31 | | 2.48% | | | |
| M&T Bank Corp | MTB | 166.854 | 151.36 | 25,255.02 | 0.07% | 3.57% | 0.00% | 5.82% | 0.00% |
| Xcel Energy Inc | XEL | 555.639 | 53.41 | 29,676.68 | 0.09% | 4.10% | 0.00% | 7.13% | 0.01% |
| Fifth Third Bancorp | FITB | 684.045 | 36.49 | 24,960.80 | | 3.84% | | 25.00% | |
| Gilead Sciences Inc | GILD | 1245.853 | 68.61 | 85,477.97 | 0.25% | 4.49% | 0.01% | 14.05% | 0.03% |
| Hasbro Inc | HAS | 139.216 | 58.5 | 8,144.14 | | 4.79% | | 25.99% | |
| Huntington Bancshares Inc/OH | HBAN | 1449.254 | 13.18 | 19,101.17 | 0.05% | 4.70% | 0.00% | 4.46% | 0.00% |
| Welltower Inc | WELL | 597.916 | 104.25 | 62,332.74 | 0.18% | 2.34% | 0.00% | 14.68% | 0.03% |
| Biogen Inc | BIIB | 145.597 | 231.82 | 33,752.30 | 0.10% | | | 5.36% | 0.01% |

| Name | Ticker | [4] Shares Outst'g | [5] Price | [6] Market Capitalization | [7] Weight in Index | [8] Estimated Dividend Yield | [9] Cap-Weighted Dividend Yield | [10] Bloomberg Long-Term Growth Est. | [11] Cap-Weighted Long-Term Growth Est. |
|---|---|---|---|---|---|---|---|---|---|
| Northern Trust Corp | NTRS | 204.592 | 83.98 | 17,181.64 | 0.05% | 3.57% | 0.00% | 10.80% | 0.01% |
| Packaging Corp of America | PKG | 89.798 | 182.56 | 16,393.52 | 0.05% | 2.74% | 0.00% | 4.44% | 0.00% |
| Paychex Inc | PAYX | 359.963 | 118.56 | 42,677.21 | | 3.31% | | | |
| QUALCOMM Inc | QCOM | 1116 | 199.18 | 222,284.88 | 0.64% | 1.71% | 0.01% | 11.88% | 0.08% |
| Ross Stores Inc | ROST | 333.575 | 145.32 | 48,475.12 | | 1.01% | | 188.00% | |
| IDEXX Laboratories Inc | IDXX | 82.587 | 487.2 | 40,236.39 | 0.12% | | | 11.11% | 0.01% |
| Starbucks Corp | SBUX | 1132.7 | 77.85 | 88,180.70 | 0.25% | 2.93% | 0.01% | 10.71% | 0.03% |
| KeyCorp | KEY | 942.86 | 14.21 | 13,398.04 | 0.04% | 5.77% | 0.00% | 19.11% | 0.01% |
| Fox Corp | FOXA | 231.15 | 34.37 | 7,944.63 | 0.02% | 1.51% | 0.00% | 6.84% | 0.00% |
| Fox Corp | FOX | 235.581 | 32.02 | 7,543.30 | 0.02% | 1.62% | 0.00% | 6.84% | 0.00% |
| State Street Corp | STT | 301.259 | 73.31 | 22,085.30 | 0.06% | 3.76% | 0.00% | 8.07% | 0.01% |
| Norwegian Cruise Line Holdings Ltd | NCLH | 429.041 | 18.79 | 8,061.68 | | | | 51.83% | |
| US Bancorp | USB | 1560.46 | 39.7 | 61,950.26 | 0.18% | 4.94% | 0.01% | 2.71% | 0.00% |
| A O Smith Corp | AOS | 120.784 | 81.78 | 9,877.72 | | 1.57% | | | |
| Gen Digital Inc | GEN | 626.146 | 24.98 | 15,641.13 | 0.04% | 2.00% | 0.00% | 10.16% | 0.00% |
| T Rowe Price Group Inc | TROW | 223.3 | 115.31 | 25,748.72 | 0.07% | 4.30% | 0.00% | 5.88% | 0.00% |
| Waste Management Inc | WM | 401.083 | 213.34 | 85,567.05 | 0.25% | 1.41% | 0.00% | 11.11% | 0.03% |
| Constellation Brands Inc | STZ | 182.354 | 257.28 | 46,916.04 | 0.13% | 1.57% | 0.00% | 11.21% | 0.02% |
| Invesco Ltd | IVZ | 449.831 | 14.96 | 6,729.47 | 0.02% | 5.48% | 0.00% | 8.71% | 0.00% |
| Intuit Inc | INTU | 279.547 | 657.21 | 183,721.08 | 0.53% | 0.55% | 0.00% | 15.15% | 0.08% |
| Morgan Stanley | MS | 1625.163 | 97.19 | 157,949.59 | 0.45% | 3.50% | 0.02% | 9.49% | 0.04% |
| Microchip Technology Inc | MCHP | 536.886 | 91.5 | 49,125.07 | | 1.98% | | -9.39% | |
| Crowdstrike Holdings Inc | CRWD | 230.883 | 383.19 | 88,472.06 | 0.25% | | | 19.85% | 0.05% |
| Chubb Ltd | CB | 406.061 | 255.08 | 103,578.04 | 0.30% | 1.43% | 0.00% | 1.99% | 0.01% |
| Hologic Inc | HOLX | 233.377 | 74.25 | 17,328.24 | 0.05% | | | 7.36% | 0.00% |
| Citizens Financial Group Inc | CFG | 455.02 | 36.03 | 16,394.37 | | 4.66% | | | |
| Jabil Inc | JBL | 120.597 | 108.79 | 13,119.75 | 0.04% | 0.29% | 0.00% | 7.13% | 0.00% |
| O'Reilly Automotive Inc | ORLY | 58.894 | 1056.06 | 62,195.60 | 0.18% | | | 11.00% | 0.02% |
| Allstate Corp/The | ALL | 263.915 | 159.66 | 42,136.67 | | 2.30% | | 169.00% | |
| Equity Residential | EQR | 378.94 | 68.665 | 26,019.92 | 0.07% | 3.93% | 0.00% | 3.98% | 0.00% |
| BorgWarner Inc | BWA | 227.838 | 32.24 | 7,345.50 | 0.02% | 1.36% | 0.00% | 4.17% | 0.00% |
| Keurig Dr Pepper Inc | KDP | 1355.574 | 33.4 | 45,276.17 | 0.13% | 2.57% | 0.00% | 7.06% | 0.01% |
| Host Hotels & Resorts Inc | HST | 703.6 | 17.98 | 12,650.73 | | 4.45% | | -0.49% | |
| Incyte Corp | INCY | 224.855 | 60.62 | 13,630.71 | 0.04% | | | 19.22% | 0.01% |
| Simon Property Group Inc | SPG | 325.766 | 151.8 | 49,451.28 | 0.14% | 5.27% | 0.01% | 1.31% | 0.00% |
| Eastman Chemical Co | EMN | 117.649 | 97.97 | 11,526.07 | 0.03% | 3.31% | 0.00% | 6.19% | 0.00% |
| AvalonBay Communities Inc | AVB | 142.186 | 206.89 | 29,416.86 | 0.08% | 3.29% | 0.00% | 7.71% | 0.01% |
| Prudential Financial Inc | PRU | 359 | 117.19 | 42,071.21 | 0.12% | 4.44% | 0.01% | 9.96% | 0.01% |
| United Parcel Service Inc | UPS | 729.399 | 136.85 | 99,818.25 | 0.29% | 4.76% | 0.01% | 6.39% | 0.02% |
| Walgreens Boots Alliance Inc | WBA | 863.275 | 12.095 | 10,441.31 | | 8.27% | | -10.00% | |
| STERIS PLC | STE | 98.9 | 219.54 | 21,712.51 | | 0.95% | | | |
| McKesson Corp | MCK | 129.711 | 584.04 | 75,756.41 | 0.22% | 0.42% | 0.00% | 11.67% | 0.03% |
| Lockheed Martin Corp | LMT | 239.938 | 467.1 | 112,075.04 | 0.32% | 2.70% | 0.01% | 2.21% | 0.01% |
| Cencora Inc | COR | 196.929 | 225.3 | 44,368.10 | 0.13% | 0.91% | 0.00% | 10.82% | 0.01% |
| Capital One Financial Corp | COF | 381.922 | 138.45 | 52,877.10 | 0.15% | 1.73% | 0.00% | 12.00% | 0.02% |
| Waters Corp | WAT | 59.32 | 290.12 | 17,209.92 | 0.05% | | | 5.12% | 0.00% |
| Nordson Corp | NDSN | 57.269 | 231.94 | 13,282.97 | | 1.17% | | | |
| Dollar Tree Inc | DLTR | 214.944 | 106.77 | 22,949.57 | 0.07% | | | 12.39% | 0.01% |
| Darden Restaurants Inc | DRI | 119.359 | 151.32 | 18,061.40 | 0.05% | 3.70% | 0.00% | 9.82% | 0.01% |
| Evergy Inc | EVRG | 229.746 | 52.97 | 12,169.65 | 0.03% | 4.85% | 0.00% | 5.00% | 0.00% |
| Match Group Inc | MTCH | 265.668 | 30.38 | 8,070.99 | | | | 35.69% | |
| Domino's Pizza Inc | DPZ | 34.88 | 516.33 | 18,009.59 | 0.05% | 1.17% | 0.00% | 14.43% | 0.01% |
| NVR Inc | NVR | 3.132 | 7588.56 | 23,767.37 | 0.07% | | | 4.87% | 0.00% |
| NetApp Inc | NTAP | 205.802 | 128.8 | 26,507.30 | 0.08% | 1.61% | 0.00% | 5.26% | 0.00% |
| Old Dominion Freight Line Inc | ODFL | 217.285 | 176.6 | 38,372.53 | 0.11% | 0.59% | 0.00% | 5.45% | 0.01% |
| DaVita Inc | DVA | 87.7 | 138.57 | 12,152.59 | 0.03% | | | 15.98% | 0.01% |
| Hartford Financial Services Group Inc/The | HIG | 295.755 | 100.54 | 29,735.21 | 0.09% | 1.87% | 0.00% | 12.22% | 0.01% |
| Iron Mountain Inc | IRM | 293.133 | 89.62 | 26,270.58 | 0.08% | 2.90% | 0.00% | 4.00% | 0.00% |
| Estee Lauder Cos Inc/The | EL | 233.022 | 106.4 | 24,793.54 | 0.07% | 2.48% | 0.00% | 16.13% | 0.01% |
| Cadence Design Systems Inc | CDNS | 273.875 | 307.75 | 84,285.03 | 0.24% | | | 15.67% | 0.04% |
| Tyler Technologies Inc | TYL | 42.455 | 502.78 | 21,345.52 | | | | | |
| Universal Health Services Inc | UHS | 59.678 | 184.93 | 11,036.25 | 0.03% | 0.43% | 0.00% | 17.84% | 0.01% |
| Skyworks Solutions Inc | SWKS | 160.447 | 106.58 | 17,100.44 | | 2.55% | | -1.59% | |
| Quest Diagnostics Inc | DGX | 111.092 | 136.88 | 15,206.27 | | 2.19% | | -0.82% | |
| Rockwell Automation Inc | ROK | 114.003 | 275.28 | 31,382.75 | 0.09% | 1.82% | 0.00% | 5.23% | 0.00% |
| Kraft Heinz Co/The | KHC | 1214.298 | 32.22 | 39,124.68 | 0.11% | 4.97% | 0.01% | 3.77% | 0.00% |
| American Tower Corp | AMT | 466.975 | 194.38 | 90,770.60 | 0.26% | 3.33% | 0.01% | 11.49% | 0.03% |
| Regeneron Pharmaceuticals Inc | REGN | 108.367 | 1051.03 | 113,896.97 | | | | 34.31% | |
| Amazon.com Inc | AMZN | 10406.627 | 193.25 | 2,011,080.67 | | | | 28.96% | |
| Jack Henry & Associates Inc | JKHY | 72.9 | 166.02 | 12,102.86 | 0.03% | 1.33% | 0.00% | 7.46% | 0.00% |
| Ralph Lauren Corp | RL | 40.774 | 175.06 | 7,137.90 | 0.02% | 1.89% | 0.00% | 11.05% | 0.00% |
| BXP Inc | BXP | 157.049 | 61.56 | 9,667.94 | 0.03% | 6.37% | 0.00% | 0.23% | 0.00% |
| Amphenol Corp | APH | 1201.208 | 67.37 | 80,925.38 | 0.23% | 0.65% | 0.00% | 13.37% | 0.03% |
| Howmet Aerospace Inc | HWM | 408.183 | 77.63 | 31,687.25 | 0.09% | 0.26% | 0.00% | 19.82% | 0.02% |
| Valero Energy Corp | VLO | 326.996 | 156.76 | 51,259.89 | | 2.73% | | -24.00% | |
| Synopsys Inc | SNPS | 153.216 | 595.06 | 91,172.71 | 0.26% | | | 16.59% | 0.04% |
| Etsy Inc | ETSY | 116.933 | 58.98 | 6,896.71 | 0.02% | | | 7.51% | 0.00% |
| CH Robinson Worldwide Inc | CHRW | 117.095 | 88.12 | 10,318.41 | 0.03% | 2.77% | 0.00% | 13.90% | 0.00% |
| Accenture PLC | ACN | 628.729 | 303.41 | 190,762.67 | 0.55% | 1.70% | 0.01% | 5.80% | 0.03% |
| TransDigm Group Inc | TDG | 55.958 | 1277.61 | 71,492.50 | 0.21% | | | 16.91% | 0.03% |
| Yum! Brands Inc | YUM | 281.632 | 132.46 | 37,304.97 | 0.11% | 2.02% | 0.00% | 10.66% | 0.01% |
| Prologis Inc | PLD | 925.844 | 112.31 | 103,981.54 | 0.30% | 3.42% | 0.01% | 7.57% | 0.02% |
| FirstEnergy Corp | FE | 575.516 | 38.27 | 22,025.00 | 0.06% | 4.44% | 0.00% | 5.65% | 0.00% |
| VeriSign Inc | VRSN | 100.139 | 177.8 | 17,804.71 | | | | | |
| Quanta Services Inc | PWR | 146.388 | 254.0001 | 37,182.57 | 0.11% | 0.14% | 0.00% | 12.00% | 0.01% |
| Henry Schein Inc | HSIC | 128.051 | 64.1 | 8,208.07 | 0.02% | | | 7.53% | 0.00% |
| Ameren Corp | AEE | 266.511 | 71.11 | 18,951.60 | 0.05% | 3.77% | 0.00% | 6.00% | 0.00% |
| ANSYS Inc | ANSS | 87.3 | 321.5 | 28,066.95 | 0.08% | | | 6.37% | 0.01% |
| FactSet Research Systems Inc | FDS | 38.116 | 408.27 | 15,561.62 | 0.04% | 1.02% | 0.00% | 9.34% | 0.00% |
| NVIDIA Corp | NVDA | 24600 | 123.54 | 3,039,084.00 | | 0.03% | | 42.80% | |
| Cognizant Technology Solutions Corp | CTSH | 497.199 | 68 | 33,809.53 | 0.10% | 1.76% | 0.00% | 5.15% | 0.00% |
| Intuitive Surgical Inc | ISRG | 354.706 | 444.85 | 157,790.96 | 0.45% | | | 16.41% | 0.07% |
| Take-Two Interactive Software Inc | TTWO | 171.385 | 155.49 | 26,648.65 | | | | 64.77% | |
| Republic Services Inc | RSG | 314.975 | 194.34 | 61,212.24 | 0.18% | 1.10% | 0.00% | 10.52% | 0.02% |

| Name | Ticker | [4] Shares Outst'g | [5] Price | [6] Market Capitalization | [7] Weight in Index | [8] Estimated Dividend Yield | [9] Cap-Weighted Dividend Yield | [10] Bloomberg Long-Term Growth Est. | [11] Cap-Weighted Long-Term Growth Est. |
|---|---|---|---|---|---|---|---|---|---|
| eBay Inc | EBAY | 506 | 53.72 | 27,182.32 | 0.08% | 2.01% | 0.00% | 8.83% | 0.01% |
| Goldman Sachs Group Inc/The | GS | 322.463 | 452.32 | 145,856.46 | 0.42% | 2.43% | 0.01% | 14.02% | 0.06% |
| SBA Communications Corp | SBAC | 107.443 | 196.3 | 21,091.06 | | 2.00% | | 23.41% | |
| Sempra | SRE | 632.846 | 76.06 | 48,134.27 | 0.14% | 3.26% | 0.00% | 6.00% | 0.01% |
| Moody's Corp | MCO | 182.6 | 420.93 | 76,861.82 | 0.22% | 0.81% | 0.00% | 11.79% | 0.03% |
| ON Semiconductor Corp | ON | 430.232 | 68.55 | 29,492.40 | 0.08% | | | 2.64% | 0.00% |
| Booking Holdings Inc | BKNG | 33.928 | 3961.5 | 134,405.77 | 0.39% | 0.88% | 0.00% | 15.03% | 0.06% |
| F5 Inc | FFIV | 58.611 | 172.23 | 10,094.57 | 0.03% | | | 7.81% | 0.00% |
| Akamai Technologies Inc | AKAM | 152.317 | 90.08 | 13,720.72 | 0.04% | | | 1.54% | 0.00% |
| Charles River Laboratories International Inc | CRL | 51.512 | 206.58 | 10,641.35 | 0.03% | | | 9.81% | 0.00% |
| MarketAxess Holdings Inc | MKTX | 37.897 | 200.53 | 7,599.49 | 0.02% | 1.48% | 0.00% | 3.07% | 0.00% |
| Devon Energy Corp | DVN | 632 | 47.4 | 29,956.80 | 0.09% | 2.95% | 0.00% | 7.22% | 0.01% |
| Bio-Techne Corp | TECH | 157.585 | 71.65 | 11,290.97 | | 0.45% | | | |
| Alphabet Inc | GOOGL | 5874 | 182.15 | 1,069,949.10 | 3.07% | 0.44% | 0.01% | 15.01% | 0.46% |
| Teleflex Inc | TFX | 47.103 | 210.33 | 9,907.17 | 0.03% | 0.65% | 0.00% | 7.51% | 0.00% |
| Allegion plc | ALLE | 87.441 | 118.15 | 10,331.15 | 0.03% | 1.63% | 0.00% | 7.25% | 0.00% |
| Netflix Inc | NFLX | 430.901 | 674.88 | 290,806.47 | | | | 35.61% | |
| Warner Bros Discovery Inc | WBD | 2450.313 | 7.44 | 18,230.33 | | | | 34.78% | |
| Agilent Technologies Inc | A | 291.761 | 129.63 | 37,820.98 | 0.11% | 0.73% | 0.00% | 5.23% | 0.01% |
| Trimble Inc | TRMB | 244.208 | 55.92 | 13,656.11 | 0.04% | | | 10.00% | 0.00% |
| Elevance Health Inc | ELV | 232.418 | 541.86 | 125,938.02 | 0.36% | 1.20% | 0.00% | 12.03% | 0.04% |
| CME Group Inc | CME | 360.062 | 196.6 | 70,788.19 | 0.20% | 2.34% | 0.00% | 4.90% | 0.01% |
| Juniper Networks Inc | JNPR | 324.988 | 36.46 | 11,849.06 | 0.03% | 2.41% | 0.00% | 4.78% | 0.00% |
| BlackRock Inc | BLK | 148.6 | 787.32 | 116,995.75 | 0.34% | 2.59% | 0.01% | 11.89% | 0.04% |
| DTE Energy Co | DTE | 206.925 | 111.01 | 22,970.74 | 0.07% | 3.68% | 0.00% | 9.20% | 0.01% |
| Celanese Corp | CE | 109.22 | 134.89 | 14,732.69 | 0.04% | 2.08% | 0.00% | 3.69% | 0.00% |
| Nasdaq Inc | NDAQ | 576.533 | 60.26 | 34,741.88 | 0.10% | 1.59% | 0.00% | 5.72% | 0.01% |
| Philip Morris International Inc | PM | 1554.557 | 101.33 | 157,523.26 | 0.45% | 5.13% | 0.02% | 8.99% | 0.04% |
| Ingersoll Rand Inc | IR | 403.432 | 90.84 | 36,647.76 | 0.11% | 0.09% | 0.00% | 16.00% | 0.02% |
| Salesforce Inc | CRM | 969 | 257.1 | 249,129.90 | 0.71% | 0.62% | 0.00% | 17.34% | 0.12% |
| Roper Technologies Inc | ROP | 107.045 | 563.66 | 60,336.98 | | 0.53% | | | |
| Huntington Ingalls Industries Inc | HII | 39.433 | 246.33 | 9,713.53 | 0.03% | 2.11% | 0.00% | 7.78% | 0.00% |
| MetLife Inc | MET | 711.123 | 70.19 | 49,913.72 | 0.14% | 3.11% | 0.00% | 13.85% | 0.02% |
| Tapestry Inc | TPR | 229.773 | 42.79 | 9,831.99 | 0.03% | 3.27% | 0.00% | 9.91% | 0.00% |
| CSX Corp | CSX | 1954.927 | 33.45 | 65,392.31 | 0.19% | 1.43% | 0.00% | 10.76% | 0.02% |
| Edwards Lifesciences Corp | EW | 601.3 | 92.37 | 55,542.08 | 0.16% | | | 9.03% | 0.01% |
| Ameriprise Financial Inc | AMP | 99.325 | 427.19 | 42,430.65 | | 1.39% | | | |
| Zebra Technologies Corp | ZBRA | 51.419 | 308.93 | 15,884.87 | | | | | |
| Zimmer Biomet Holdings Inc | ZBH | 205.728 | 108.53 | 22,327.66 | 0.06% | 0.88% | 0.00% | 7.00% | 0.00% |
| Camden Property Trust | CPT | 106.535 | 109.11 | 11,624.03 | 0.03% | 3.78% | 0.00% | 1.59% | 0.00% |
| CBRE Group Inc | CBRE | 306.824 | 89.11 | 27,341.09 | | | | | |
| Mastercard Inc | MA | 922.47 | 441.16 | 406,956.87 | 1.17% | 0.60% | 0.01% | 15.54% | 0.18% |
| CarMax Inc | KMX | 156.079 | 73.34 | 11,446.83 | 0.03% | | | 18.30% | 0.01% |
| Intercontinental Exchange Inc | ICE | 573.585 | 136.89 | 78,518.05 | 0.23% | 1.31% | 0.00% | 8.96% | 0.02% |
| Fidelity National Information Services Inc | FIS | 556.251 | 75.36 | 41,919.08 | | 1.91% | | 21.47% | |
| Chipotle Mexican Grill Inc | CMG | 1373.365 | 62.65 | 86,041.32 | | | | 22.88% | |
| Wynn Resorts Ltd | WYNN | 112.071 | 89.5 | 10,030.35 | | 1.12% | | -3.85% | |
| Live Nation Entertainment Inc | LYV | 231.443 | 93.74 | 21,695.47 | | | | | |
| Assurant Inc | AIZ | 51.986 | 166.25 | 8,642.67 | 0.02% | 1.73% | 0.00% | 6.19% | 0.00% |
| NRG Energy Inc | NRG | 208.476 | 77.86 | 16,231.94 | 0.05% | 2.09% | 0.00% | 3.00% | 0.00% |
| Monster Beverage Corp | MNST | 1041.728 | 49.95 | 52,034.31 | 0.15% | | | 12.72% | 0.02% |
| Regions Financial Corp | RF | 915.827 | 20.04 | 18,353.17 | 0.05% | 4.79% | 0.00% | 4.18% | 0.00% |
| Baker Hughes Co | BKR | 997.998 | 35.17 | 35,099.59 | | 2.39% | | 69.47% | |
| Mosaic Co/The | MOS | 321.393 | 28.9 | 9,288.26 | | 2.91% | | -18.32% | |
| Expedia Group Inc | EXPE | 127.224 | 125.99 | 16,028.95 | | | | 22.40% | |
| CF Industries Holdings Inc | CF | 182.782 | 74.12 | 13,547.80 | | 2.70% | | -4.63% | |
| APA Corp | APA | 371.192 | 29.44 | 10,927.89 | 0.03% | 3.40% | 0.00% | 18.81% | 0.01% |
| Leidos Holdings Inc | LDOS | 135.212 | 145.88 | 19,724.73 | 0.06% | 1.04% | 0.00% | 10.53% | 0.01% |
| Alphabet Inc | GOOG | 5617 | 183.42 | 1,030,270.14 | 2.95% | 0.44% | 0.01% | 15.01% | 0.44% |
| First Solar Inc | FSLR | 107.041 | 225.46 | 24,133.46 | | | | 42.58% | |
| TE Connectivity Ltd | TEL | 306.228 | 150.43 | 46,065.88 | 0.13% | 1.73% | 0.00% | 5.04% | 0.01% |
| Discover Financial Services | DFS | 250.599 | 130.81 | 32,780.86 | | 2.14% | | 61.19% | |
| Visa Inc | V | 1574.152 | 262.47 | 413,167.68 | 1.18% | 0.79% | 0.01% | 13.05% | 0.15% |
| Mid-America Apartment Communities Inc | MAA | 116.688 | 142.61 | 16,640.88 | 0.05% | 4.12% | 0.00% | 0.83% | 0.00% |
| Xylem Inc/NY | XYL | 242.447 | 135.63 | 32,883.09 | | 1.06% | | | |
| Marathon Petroleum Corp | MPC | 352.33 | 173.48 | 61,122.21 | | 1.90% | | | |
| Tractor Supply Co | TSCO | 107.81 | 270 | 29,108.70 | 0.08% | 1.63% | 0.00% | 5.15% | 0.00% |
| Advanced Micro Devices Inc | AMD | 1616.314 | 162.21 | 262,182.29 | | | | 31.82% | |
| ResMed Inc | RMD | 146.907 | 191.42 | 28,120.94 | 0.08% | 1.00% | 0.00% | 13.45% | 0.01% |
| Mettler-Toledo International Inc | MTD | 21.357 | 1397.59 | 29,848.33 | 0.09% | | | 9.29% | 0.01% |
| VICI Properties Inc | VICI | 1043.137 | 28.64 | 29,875.44 | 0.09% | 5.80% | 0.00% | 5.44% | 0.00% |
| Copart Inc | CPRT | 962.298 | 54.16 | 52,118.06 | | | | | |
| Jacobs Solutions Inc | J | 125.213 | 139.71 | 17,493.51 | 0.05% | 0.83% | 0.00% | 10.76% | 0.01% |
| Albemarle Corp | ALB | 117.527 | 95.52 | 11,226.18 | | 1.68% | | -12.68% | |
| Fortinet Inc | FTNT | 763.938 | 60.27 | 46,042.54 | 0.13% | | | 9.59% | 0.01% |
| Moderna Inc | MRNA | 383.24 | 118.75 | 45,509.75 | 0.13% | | | 17.71% | 0.02% |
| Essex Property Trust Inc | ESS | 64.206 | 272.2 | 17,476.87 | 0.05% | 3.60% | 0.00% | 4.64% | 0.00% |
| CoStar Group Inc | CSGP | 408.342 | 74.14 | 30,274.48 | 0.09% | | | 15.09% | 0.01% |
| Realty Income Corp | O | 870.774 | 52.557 | 45,765.27 | 0.13% | 6.00% | 0.01% | 2.47% | 0.00% |
| Westrock Co | WRK | 258.148 | 50.26 | 12,974.52 | 0.04% | 2.41% | 0.00% | 11.18% | 0.00% |
| Westinghouse Air Brake Technologies Corp | WAB | 176.385 | 158.05 | 27,877.65 | 0.08% | 0.51% | 0.00% | 15.49% | 0.01% |
| Pool Corp | POOL | 38.329 | 307.33 | 11,779.65 | | 1.56% | | | |
| Western Digital Corp | WDC | 326.525 | 75.77 | 24,740.80 | | | | -10.00% | |
| PepsiCo Inc | PEP | 1374.786 | 164.93 | 226,743.45 | 0.65% | 3.29% | 0.02% | 7.91% | 0.05% |
| Diamondback Energy Inc | FANG | 178.344 | 200.19 | 35,702.69 | 0.10% | 3.94% | 0.00% | 9.67% | 0.01% |
| Palo Alto Networks Inc | PANW | 323.8 | 339.01 | 109,771.44 | 0.31% | | | 14.33% | 0.05% |
| ServiceNow Inc | NOW | 205 | 786.67 | 161,267.35 | | | | 25.00% | |
| Church & Dwight Co Inc | CHD | 244.523 | 103.68 | 25,352.14 | 0.07% | 1.09% | 0.00% | 8.02% | 0.01% |
| Federal Realty Investment Trust | FRT | 82.775 | 100.97 | 8,357.79 | 0.02% | 4.32% | 0.00% | 4.11% | 0.00% |
| MGM Resorts International | MGM | 313.68 | 44.44 | 13,939.94 | 0.04% | | | 15.86% | 0.01% |
| American Electric Power Co Inc | AEP | 526.59 | 87.74 | 46,203.01 | 0.13% | 4.01% | 0.01% | 6.00% | 0.01% |
| Invitation Homes Inc | INVH | 612.536 | 35.89 | 21,983.92 | 0.06% | 3.12% | 0.00% | 5.86% | 0.00% |
| PTC Inc | PTC | 119.744 | 181.67 | 21,753.89 | 0.06% | | | 14.94% | 0.01% |
| JB Hunt Transport Services Inc | JBHT | 103.197 | 160 | 16,511.52 | 0.05% | 1.08% | 0.00% | 11.79% | 0.01% |

| Name | Ticker | [4] Shares Outst'g | [5] Price | [6] Market Capitalization | [7] Weight in Index | [8] Estimated Dividend Yield | [9] Cap-Weighted Dividend Yield | [10] Bloomberg Long-Term Growth Est. | [11] Cap-Weighted Long-Term Growth Est. |
|---|---|---|---|---|---|---|---|---|---|
| Lam Research Corp | LRCX | 130.736 | 1064.85 | 139,214.23 | 0.40% | 0.75% | 0.00% | 8.61% | 0.03% |
| Mohawk Industries Inc | MHK | 63.863 | 113.59 | 7,254.20 | 0.02% | | | 2.74% | 0.00% |
| GE HealthCare Technologies Inc | GEHC | 456.465 | 77.92 | 35,567.75 | 0.10% | 0.15% | 0.00% | 11.26% | 0.01% |
| Pentair PLC | PNR | 166.025 | 76.67 | 12,729.14 | 0.04% | 1.20% | 0.00% | 13.13% | 0.00% |
| Vertex Pharmaceuticals Inc | VRTX | 258.053 | 468.72 | 120,954.60 | 0.35% | | | 12.79% | 0.04% |
| Amcor PLC | AMCR | 1445.343 | 9.78 | 14,135.45 | 0.04% | 5.11% | 0.00% | 2.32% | 0.00% |
| Meta Platforms Inc | META | 2191.446 | 504.22 | 1,104,970.90 | 3.17% | 0.40% | 0.01% | 18.58% | 0.59% |
| T-Mobile US Inc | TMUS | 1171.854 | 176.18 | 206,457.24 | 0.59% | 1.48% | 0.01% | 5.00% | 0.03% |
| United Rentals Inc | URI | 66.59 | 646.73 | 43,065.75 | 0.12% | 1.01% | 0.00% | 5.27% | 0.01% |
| Alexandria Real Estate Equities Inc | ARE | 174.883 | 116.97 | 20,456.06 | 0.06% | 4.45% | 0.00% | 4.21% | 0.00% |
| Honeywell International Inc | HON | 651.186 | 213.54 | 139,054.26 | 0.40% | 2.02% | 0.01% | 8.98% | 0.04% |
| Delta Air Lines Inc | DAL | 645.312 | 47.44 | 30,613.60 | 0.09% | 1.26% | 0.00% | 12.00% | 0.01% |
| United Airlines Holdings Inc | UAL | 328.803 | 48.66 | 15,999.55 | 0.05% | | | 12.79% | 0.01% |
| Seagate Technology Holdings PLC | STX | 209.989 | 103.27 | 21,685.56 | | 2.71% | | | |
| News Corp | NWS | 190.684 | 28.39 | 5,413.52 | | 0.70% | | | |
| Centene Corp | CNC | 533.656 | 66.3 | 35,381.39 | 0.10% | | | 5.16% | 0.01% |
| Martin Marietta Materials Inc | MLM | 61.64 | 541.8 | 33,396.55 | 0.10% | 0.55% | 0.00% | 9.77% | 0.01% |
| Teradyne Inc | TER | 156.112 | 148.29 | 23,149.85 | 0.07% | 0.32% | 0.00% | 17.47% | 0.01% |
| PayPal Holdings Inc | PYPL | 1046.046 | 58.03 | 60,702.05 | 0.17% | | | 8.69% | 0.02% |
| Tesla Inc | TSLA | 3189.196 | 197.88 | 631,078.10 | | | | -7.00% | |
| KKR & Co Inc | KKR | 887.402 | 105.24 | 93,390.19 | | 0.67% | | | |
| Arch Capital Group Ltd | ACGL | 375.494 | 100.89 | 37,883.59 | 0.11% | | | 4.41% | 0.00% |
| Dow Inc | DOW | 703.268 | 53.05 | 37,308.37 | 0.11% | 5.28% | 0.01% | 1.46% | 0.00% |
| Everest Group Ltd | EG | 43.458 | 381.02 | 16,558.37 | 0.05% | 2.10% | 0.00% | 1.85% | 0.00% |
| Teledyne Technologies Inc | TDY | 47.422 | 387.98 | 18,398.79 | 0.05% | | | 7.34% | 0.00% |
| GE Vernova Inc | GEV | 274.086 | 171.51 | 47,008.49 | | | | | |
| News Corp | NWSA | 379.205 | 27.57 | 10,454.68 | | 0.73% | | | |
| Exelon Corp | EXC | 999.735 | 34.61 | 34,600.83 | 0.10% | 4.39% | 0.00% | 5.60% | 0.01% |
| Global Payments Inc | GPN | 255.25 | 96.7 | 24,682.68 | 0.07% | 1.03% | 0.00% | 9.40% | 0.01% |
| Crown Castle Inc | CCI | 434.523 | 97.7 | 42,452.90 | 0.12% | 6.41% | 0.01% | 0.81% | 0.00% |
| Aptiv PLC | APTV | 272.062 | 70.42 | 19,158.61 | | | | 24.81% | |
| Align Technology Inc | ALGN | 75.282 | 241.43 | 18,175.33 | 0.05% | | | 11.74% | 0.01% |
| Kenvue Inc | KVUE | 1914.811 | 18.18 | 34,811.26 | 0.10% | 4.40% | 0.00% | 15.93% | 0.02% |
| Targa Resources Corp | TRGP | 221.717 | 128.78 | 28,552.72 | | 2.33% | | 21.12% | |
| Bunge Global SA | BG | 141.595 | 106.77 | 15,118.10 | | 2.55% | | -8.30% | |
| LKQ Corp | LKQ | 266.776 | 41.59 | 11,095.21 | | 2.89% | | | |
| Deckers Outdoor Corp | DECK | 25.442 | 967.95 | 24,626.58 | 0.07% | | | 8.39% | 0.01% |
| Zoetis Inc | ZTS | 456.295 | 173.36 | 79,103.30 | 0.23% | 1.00% | 0.00% | 10.36% | 0.02% |
| Equinix Inc | EQIX | 94.906 | 756.6 | 71,805.88 | 0.21% | 2.25% | 0.00% | 10.10% | 0.02% |
| Digital Realty Trust Inc | DLR | 324.502 | 152.05 | 49,340.53 | 0.14% | 3.21% | 0.00% | 2.08% | 0.00% |
| Molina Healthcare Inc | MOH | 59 | 297.3 | 17,540.70 | 0.05% | | | 11.72% | 0.01% |
| Las Vegas Sands Corp | LVS | 745.047 | 44.25 | 32,968.33 | | 1.81% | | | |

Notes:

[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Bloomberg Professional as of June 30, 2024
[5] Bloomberg Professional as of June 30, 2024
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Source: Bloomberg Professional, as of June 30, 2024
[9] Equals [7] x [8]
[10] Value Line, as of June 30, 2024
[11] Equals [7] x [10]

Docket No. UE 433
Exhibit PAC/2208
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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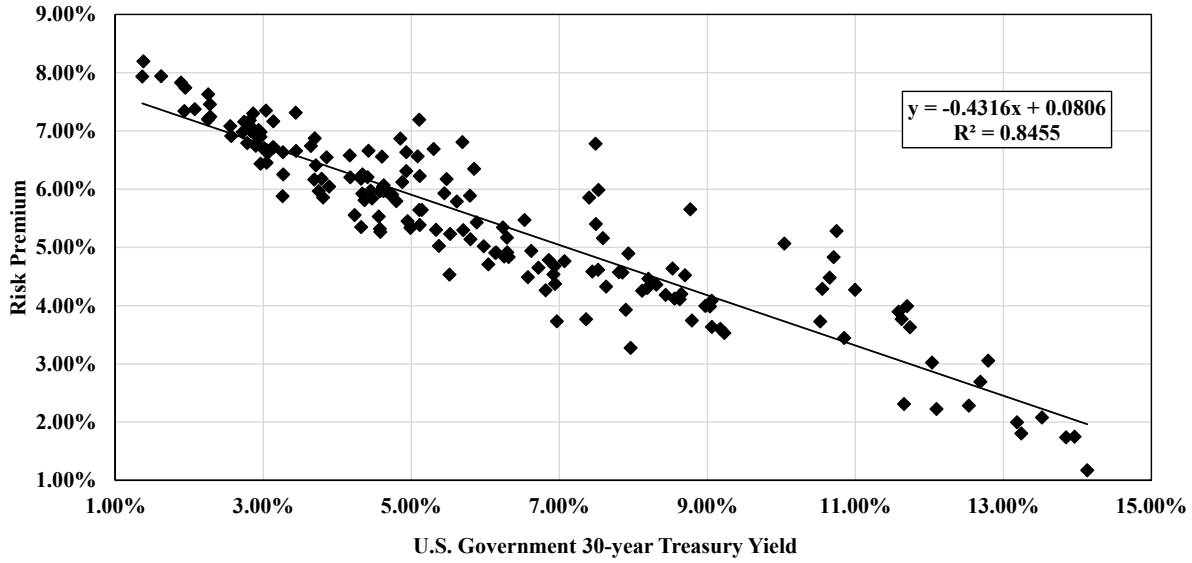
**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Risk Premium Approach**

**July 2024**




SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.9195180 |
| R Square | 0.8455134 |
| Adjusted R Square | 0.8446356 |
| Standard Error | 0.0056583 |
| Observations | 178 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 0.03084 | 0.03084 | 963.25740 | 0.00000 |
| Residual | 176 | 0.00563 | 0.00003 | | |
| Total | 177 | 0.03648 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | 0.0806 | 0.00 | 85.41 | 0.0000 | 0.0788 | 0.0825 | 0.0788 | 0.0825 |
| U.S. Govt. 30-year Treasury | (0.4316) | 0.01 | (31.04) | 0.0000 | (0.4590) | (0.4041) | (0.4590) | (0.4041) |

| | U.S. Govt. 30-year Treasury | Risk Premium | ROE |
|---|---|---|---|
| Current 30-day average of 30-year U.S. Treasury bond yield [4] | 4.50% | 6.12% | 10.62% |
| Blue Chip Near-Term Projected Forecast (Q4 2024 - Q4 2025) [5] | 4.32% | 6.20% | 10.52% |
| Blue Chip Long-Term Projected Forecast (2026-2030) [6] | 4.30% | 6.21% | 10.51% |
| AVERAGE | | | 10.55% |

Notes:
[1] Regulatory Research Associates, rate cases through June 30, 2024
[2] S&P Capital IQ Pro, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] S&P Capital IQ Pro, 30-day average as of June 30, 2024
[5] Source: Blue Chip Financial Forecasts, Vol. 43, No. 7, June 30, 2024, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.080636 + (-0.431577 x Column [7])
[9] Equals Column [7] + Column [8]

BOND YIELD PLUS RISK PREMIUM

| | [1] | [2] | [3] |
|---|---|---|---|
| Quarter | Average Authorized VI Electric ROE | U.S. Govt. 30-year Treasury | Risk Premium |
| 1980.1 | 13.97% | 11.66% | 2.31% |
| 1980.2 | 14.25% | 10.52% | 3.73% |
| 1980.3 | 14.30% | 10.85% | 3.45% |
| 1980.4 | 14.32% | 12.10% | 2.23% |
| 1981.1 | 14.82% | 12.53% | 2.28% |
| 1981.2 | 15.05% | 13.24% | 1.81% |
| 1981.3 | 15.31% | 14.13% | 1.17% |
| 1981.4 | 15.59% | 13.85% | 1.74% |
| 1982.1 | 15.71% | 13.96% | 1.75% |
| 1982.2 | 15.60% | 13.52% | 2.08% |
| 1982.3 | 15.85% | 12.79% | 3.06% |
| 1982.4 | 16.03% | 10.75% | 5.28% |
| 1983.1 | 15.54% | 10.71% | 4.83% |
| 1983.2 | 15.13% | 10.65% | 4.48% |
| 1983.3 | 15.39% | 11.62% | 3.77% |
| 1983.4 | 15.37% | 11.74% | 3.63% |
| 1984.1 | 15.06% | 12.04% | 3.02% |
| 1984.2 | 15.18% | 13.18% | 2.00% |
| 1984.3 | 15.38% | 12.69% | 2.69% |
| 1984.4 | 15.69% | 11.70% | 3.99% |
| 1985.1 | 15.48% | 11.58% | 3.90% |
| 1985.2 | 15.27% | 11.00% | 4.27% |
| 1985.3 | 14.84% | 10.55% | 4.29% |
| 1985.4 | 15.11% | 10.04% | 5.07% |
| 1986.1 | 14.42% | 8.77% | 5.65% |
| 1986.2 | 14.27% | 7.49% | 6.78% |
| 1986.3 | 13.26% | 7.40% | 5.86% |
| 1986.4 | 13.52% | 7.53% | 5.99% |
| 1987.1 | 12.90% | 7.49% | 5.40% |
| 1987.2 | 13.17% | 8.53% | 4.64% |
| 1987.3 | 13.14% | 9.06% | 4.08% |
| 1987.4 | 12.76% | 9.23% | 3.53% |
| 1988.1 | 12.74% | 8.63% | 4.11% |
| 1988.2 | 12.70% | 9.06% | 3.63% |
| 1988.3 | 12.78% | 9.18% | 3.60% |
| 1988.4 | 12.97% | 8.97% | 4.00% |
| 1989.1 | 13.02% | 9.04% | 3.99% |
| 1989.2 | 13.22% | 8.70% | 4.52% |
| 1989.3 | 12.38% | 8.12% | 4.26% |
| 1989.4 | 12.83% | 7.93% | 4.90% |
| 1990.1 | 12.62% | 8.44% | 4.19% |
| 1990.2 | 12.85% | 8.65% | 4.20% |
| 1990.3 | 12.54% | 8.79% | 3.75% |
| 1990.4 | 12.68% | 8.56% | 4.12% |
| 1991.1 | 12.66% | 8.20% | 4.46% |
| 1991.2 | 12.67% | 8.31% | 4.36% |
| 1991.3 | 12.49% | 8.19% | 4.30% |
| 1991.4 | 12.42% | 7.85% | 4.57% |
| 1992.1 | 12.38% | 7.81% | 4.58% |
| 1992.2 | 11.83% | 7.90% | 3.93% |
| 1992.3 | 12.03% | 7.45% | 4.59% |
| 1992.4 | 12.14% | 7.52% | 4.62% |
| 1993.1 | 11.84% | 7.07% | 4.76% |
| 1993.2 | 11.64% | 6.86% | 4.78% |
| 1993.3 | 11.15% | 6.32% | 4.84% |
| 1993.4 | 11.04% | 6.14% | 4.91% |
| 1994.1 | 11.07% | 6.58% | 4.49% |
| 1994.2 | 11.13% | 7.36% | 3.77% |
| 1994.3 | 12.75% | 7.59% | 5.16% |
| 1994.4 | 11.24% | 7.96% | 3.28% |
| 1995.1 | 11.96% | 7.63% | 4.33% |
| 1995.2 | 11.32% | 6.94% | 4.37% |
| 1995.3 | 11.37% | 6.72% | 4.65% |

BOND YIELD PLUS RISK PREMIUM

| Quarter | [1] Average Authorized VI Electric ROE | [2] U.S. Govt. 30-year Treasury | [3] Risk Premium |
|---|---|---|---|
| 1995.4 | 11.58% | 6.24% | 5.35% |
| 1996.1 | 11.46% | 6.29% | 5.17% |
| 1996.2 | 11.46% | 6.92% | 4.54% |
| 1996.3 | 10.70% | 6.97% | 3.73% |
| 1996.4 | 11.56% | 6.62% | 4.94% |
| 1997.1 | 11.08% | 6.82% | 4.26% |
| 1997.2 | 11.62% | 6.94% | 4.68% |
| 1997.3 | 12.00% | 6.53% | 5.47% |
| 1997.4 | 11.06% | 6.15% | 4.91% |
| 1998.1 | 11.31% | 5.88% | 5.43% |
| 1998.2 | 12.20% | 5.85% | 6.35% |
| 1998.3 | 11.65% | 5.48% | 6.17% |
| 1998.4 | 12.30% | 5.11% | 7.19% |
| 1999.1 | 10.40% | 5.37% | 5.03% |
| 1999.2 | 10.94% | 5.80% | 5.14% |
| 1999.3 | 10.75% | 6.04% | 4.71% |
| 1999.4 | 11.10% | 6.26% | 4.84% |
| 2000.1 | 11.21% | 6.30% | 4.92% |
| 2000.2 | 11.00% | 5.98% | 5.02% |
| 2000.3 | 11.68% | 5.79% | 5.89% |
| 2000.4 | 12.50% | 5.69% | 6.81% |
| 2001.1 | 11.38% | 5.45% | 5.93% |
| 2001.2 | 11.00% | 5.70% | 5.30% |
| 2001.3 | 10.76% | 5.53% | 5.23% |
| 2001.4 | 11.99% | 5.30% | 6.69% |
| 2002.1 | 10.05% | 5.52% | 4.53% |
| 2002.2 | 11.41% | 5.62% | 5.79% |
| 2002.3 | 11.65% | 5.09% | 6.56% |
| 2002.4 | 11.57% | 4.93% | 6.63% |
| 2003.1 | 11.72% | 4.85% | 6.87% |
| 2003.2 | 11.16% | 4.60% | 6.56% |
| 2003.3 | 10.50% | 5.11% | 5.39% |
| 2003.4 | 11.34% | 5.11% | 6.23% |
| 2004.1 | 11.00% | 4.88% | 6.12% |
| 2004.2 | 10.64% | 5.34% | 5.30% |
| 2004.3 | 10.75% | 5.11% | 5.64% |
| 2004.4 | 11.24% | 4.93% | 6.31% |
| 2005.1 | 10.63% | 4.71% | 5.92% |
| 2005.2 | 10.31% | 4.47% | 5.84% |
| 2005.3 | 11.08% | 4.42% | 6.66% |
| 2005.4 | 10.63% | 4.65% | 5.98% |
| 2006.1 | 10.70% | 4.63% | 6.07% |
| 2006.2 | 10.79% | 5.14% | 5.64% |
| 2006.3 | 10.35% | 5.00% | 5.35% |
| 2006.4 | 10.65% | 4.74% | 5.91% |
| 2007.1 | 10.59% | 4.80% | 5.79% |
| 2007.2 | 10.33% | 4.99% | 5.34% |
| 2007.3 | 10.40% | 4.95% | 5.45% |
| 2007.4 | 10.65% | 4.61% | 6.04% |
| 2008.1 | 10.62% | 4.41% | 6.21% |
| 2008.2 | 10.54% | 4.57% | 5.96% |
| 2008.3 | 10.43% | 4.45% | 5.98% |
| 2008.4 | 10.39% | 3.64% | 6.74% |
| 2009.1 | 10.75% | 3.44% | 7.31% |
| 2009.2 | 10.75% | 4.17% | 6.58% |
| 2009.3 | 10.50% | 4.32% | 6.18% |
| 2009.4 | 10.59% | 4.34% | 6.25% |
| 2010.1 | 10.59% | 4.62% | 5.97% |
| 2010.2 | 10.18% | 4.37% | 5.81% |
| 2010.3 | 10.40% | 3.86% | 6.55% |
| 2010.4 | 10.38% | 4.17% | 6.20% |
| 2011.1 | 10.09% | 4.56% | 5.53% |
| 2011.2 | 10.26% | 4.34% | 5.92% |

BOND YIELD PLUS RISK PREMIUM

| | [1] | [2] | [3] |
|---|---|---|---|
| Quarter | Average Authorized VI Electric ROE | U.S. Govt. 30-year Treasury | Risk Premium |
| 2011.3 | 10.57% | 3.70% | 6.88% |
| 2011.4 | 10.39% | 3.04% | 7.35% |
| 2012.1 | 10.30% | 3.14% | 7.17% |
| 2012.2 | 9.95% | 2.94% | 7.01% |
| 2012.3 | 9.90% | 2.74% | 7.16% |
| 2012.4 | 10.16% | 2.86% | 7.30% |
| 2013.1 | 9.85% | 3.13% | 6.72% |
| 2013.2 | 9.86% | 3.14% | 6.72% |
| 2013.3 | 10.12% | 3.71% | 6.41% |
| 2013.4 | 9.97% | 3.79% | 6.18% |
| 2014.1 | 9.86% | 3.69% | 6.16% |
| 2014.2 | 10.10% | 3.44% | 6.66% |
| 2014.3 | 9.90% | 3.27% | 6.63% |
| 2014.4 | 9.94% | 2.96% | 6.98% |
| 2015.1 | 9.64% | 2.55% | 7.08% |
| 2015.2 | 9.83% | 2.88% | 6.94% |
| 2015.3 | 9.40% | 2.96% | 6.44% |
| 2015.4 | 9.86% | 2.96% | 6.90% |
| 2016.1 | 9.70% | 2.72% | 6.98% |
| 2016.2 | 9.48% | 2.57% | 6.91% |
| 2016.3 | 9.74% | 2.28% | 7.46% |
| 2016.4 | 9.83% | 2.83% | 7.00% |
| 2017.1 | 9.72% | 3.05% | 6.67% |
| 2017.2 | 9.64% | 2.90% | 6.75% |
| 2017.3 | 10.00% | 2.82% | 7.18% |
| 2017.4 | 9.91% | 2.82% | 7.09% |
| 2018.1 | 9.69% | 3.02% | 6.66% |
| 2018.2 | 9.75% | 3.09% | 6.66% |
| 2018.3 | 9.69% | 3.06% | 6.63% |
| 2018.4 | 9.52% | 3.27% | 6.25% |
| 2019.1 | 9.72% | 3.01% | 6.70% |
| 2019.2 | 9.58% | 2.78% | 6.79% |
| 2019.3 | 9.53% | 2.29% | 7.25% |
| 2019.4 | 9.89% | 2.26% | 7.63% |
| 2020.1 | 9.72% | 1.89% | 7.83% |
| 2020.2 | 9.58% | 1.38% | 8.19% |
| 2020.3 | 9.30% | 1.37% | 7.93% |
| 2020.4 | 9.56% | 1.62% | 7.94% |
| 2021.1 | 9.45% | 2.07% | 7.38% |
| 2021.2 | 9.47% | 2.26% | 7.21% |
| 2021.3 | 9.27% | 1.93% | 7.34% |
| 2021.4 | 9.69% | 1.95% | 7.74% |
| 2022.1 | 9.45% | 2.25% | 7.20% |
| 2022.2 | 9.50% | 3.05% | 6.45% |
| 2022.3 | 9.14% | 3.26% | 5.88% |
| 2022.4 | 9.94% | 3.89% | 6.04% |
| 2023.1 | 9.72% | 3.75% | 5.97% |
| 2023.2 | 9.67% | 3.81% | 5.86% |
| 2023.3 | 9.79% | 4.23% | 5.55% |
| 2023.4 | 9.85% | 4.58% | 5.27% |
| 2024.1 | 9.67% | 4.32% | 5.35% |
| 2024.2 | 9.90% | 4.58% | 5.32% |
| AVERAGE | 11.51% | 6.07% | 5.45% |
| MEDIAN | 11.02% | 5.32% | 5.64% |

Docket No. UE 433
Exhibit PAC/2209
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Business Segment Data**

**July 2024**

**BUSINESS SEGMENT DATA FOR BLACK HILLS CORPORATION, SEMPRA ENERGY, WEC ENERGY GROUP & FORTIS, INC.**

**Black Hills Corporation - Revenue (USD$000)**

| | | Electric Utilities | | Gas Utilities | | | Inter-company | | Percent Reg / | Percent Reg | Percent Reg |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Total | Regulated | Unregulated | Regulated | Unregulated | Corporate | Eliminations | Notes | Total | Electric / Total | Gas / Total |
| 2022 | 2,551,816 | 852,141 | 48,021 | 1,584,634 | 84,456 | 368,739 | (386,175) | [1] | 95.49% | 33.39% | 62.10% |
| 2021 | 1,949,102 | 800,747 | 41,511 | 1,051,610 | 73,255 | 356,347 | (374,368) | [1] | 95.04% | 41.08% | 53.95% |
| 2020 | 1,696,941 | 699,712 | 39,145 | 900,637 | 74,033 | 353,143 | (369,729) | [1] | 94.31% | 41.23% | 53.07% |
| **3 yr. average** | | | | | | | | | **94.95%** | **38.57%** | **56.38%** |

**Sempra Energy - Revenue (USD$millions)**

| Year | Total | SDG&E | SoCalGas | Sempra Texas Utilities | Sempra Infrastructure | Sempra Renewables | All Other | Adjustments and eliminations | Intersegment Revenues | Discontinued Operations | Notes | Percent Reg / Total | Percent Reg Electric / Total | Percent Reg Gas / Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2022 | 18,646 | 5,838 | 6,840 | 4,208 | 1,919 | - | 5 | (1) | (163) | - | [2] | 90.56% | 48.28% | 42.28% |
| 2021 | 16,680 | 5,504 | 5,515 | 3,823 | 1,997 | - | 5 | (1) | (163) | - | [2] | 88.98% | 50.89% | 38.09% |
| 2020 | 14,990 | 5,313 | 4,748 | 3,620 | 1,400 | - | 2 | (3) | (90) | - | [2] | 91.27% | 54.96% | 36.30% |
| **3 yr. average** | | | | | | | | | | | | **90.27%** | **51.38%** | **38.89%** |

| | SDG&E Electric Revenues | SDG&E Gas Revenues | % Electric | % Gas |
|---|---|---|---|---|
| 2022 | 4,795 | 1,043 | 82.13% | 17.87% |
| 2021 | 4,666 | 838 | 84.77% | 15.23% |
| 2020 | 4,619 | 694 | 86.94% | 13.06% |

**WEC Energy Group, Inc. - Revenue (USD $000)**

| Year | Total | Wisconsin Electric | Wisconsin Natural Gas | Illinois Natural Gas | Other States Natural Gas | Electric Transmission | Non-Utility Energy Infrastructure | Corporate and Other | Reconciling Eliminations | Notes | Percent Reg / Total | Percent Reg Electric / Total | Percent Reg Gas / Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2022 | 9,597,400 | 4,971,800 | 1,988,700 | 1,890,900 | 618,500 | - | 590,000 | 500 | (463,000) | [3] | 98.67% | 51.80% | 46.87% |
| 2021 | 8,316,000 | 4,538,600 | 1,498,400 | 1,672,800 | 519,000 | - | 539,500 | 500 | (452,800) | [3] | 98.95% | 54.58% | 44.37% |
| 2020 | 7,241,700 | 4,274,000 | 1,199,500 | 1,321,900 | 384,100 | - | 508,500 | 2,200 | (448,500) | [3] | 99.14% | 59.02% | 40.12% |
| **3 yr. average** | | | | | | | | | | | **98.92%** | **55.13%** | **43.79%** |

**Fortis, Inc. - Operating Income (CAD $000)**

| Year | Total | ITC | UNS | Central Hudson | FortisBC Energy | Fortis Alberta | FortisBC Electric | Other Electric | Energy Infrastructure | Corporate & Other | Notes | Percent US / Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2022 | 2,740,000 | 1,040,000 | 489,000 | 125,000 | 367,000 | 271,000 | 146,000 | 235,000 | 89,000 | (22,000) | [4] | 60.36% |
| 2021 | 2,469,000 | 934,000 | 422,000 | 126,000 | 366,000 | 256,000 | 139,000 | 221,000 | 45,000 | (40,000) | [4] | 60.02% |
| 2020 | 2,508,000 | 1,011,000 | 456,000 | 128,000 | 339,000 | 236,000 | 127,000 | 215,000 | 39,000 | (43,000) | [4] | 63.60% |
| **3 yr. average** | | | | | | | | | | | | **61.33%** |

**Notes:**

[1] Source: BKH - 2022 Form 10-K, pp. 41, 106, 108; and 2021 Form 10-K, pgs. 38, 111-113
[2] Source: SRE - 2022 Form 10-K pp. F-16, F-22, F-53, F-140, F-141, Exhibit 99.1 pg. 7
[3] Source: WEC - 2022 Form 10-K pp. 49, 50, 54, 137-138; and 2021 Form 10-K, pgs. 49.
[4] Source: Fortis, Inc. - 2022 Annual Report pp. 20; and 2020 Annual Report pp. 79.

Docket No. UE 433
Exhibit PAC/2210
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Revised Staff Constant Growth DCF Analysis**

**July 2024**

STAFF CONSTANT GROWTH DCF -- AS FILED

| Company | Ticker | Company Proxy Group | Staff Proxy Group | [1] Value Line Annual Dividend (2024) | [2] Stock Price at 12/1/2023 | [3] Stock Price at 1/1/2024 | [4] Stock Price at 2/1/2024 | [5] Average Stock Price | [6] Expected Dividend Yield | [7] Value Line Dividend Growth | [8] ROE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Alliant Energy Corporation | LNT | Yes | Yes | $1.92 | $51.30 | $48.85 | $48.97 | $49.71 | 3.86% | 6.01% | 9.87% |
| Ameren Corporation | AEE | Yes | Yes | $2.65 | $72.34 | $69.51 | $70.26 | $70.70 | 3.75% | 7.10% | 10.85% |
| American Electric Power Company, Inc. | AEP | Yes | | $3.52 | $81.22 | $77.84 | $78.65 | $79.24 | 4.44% | 5.58% | 10.02% |
| Avista Corporation | AVA | Yes | Yes | $1.92 | $35.74 | $33.78 | $33.82 | $34.45 | 5.57% | 4.49% | 10.07% |
| Black Hills Corporation | BKH | | Yes | $2.65 | $53.95 | $50.80 | $51.81 | $52.19 | 5.08% | 4.66% | 9.74% |
| CMS Energy Corporation | CMS | Yes | | $2.04 | $58.07 | $56.39 | $58.09 | $57.52 | 3.55% | 4.79% | 8.34% |
| Consolidated Edison, Inc. | ED | | Yes | $3.34 | $90.97 | $90.02 | $91.82 | $90.94 | 3.67% | 3.68% | 7.36% |
| Duke Energy Corporation | DUK | Yes | | $4.14 | $97.04 | $95.87 | $97.13 | $96.68 | 4.28% | 1.64% | 5.92% |
| Entergy Corporation | ETR | Yes | | $4.56 | $101.19 | $99.31 | $101.10 | $100.53 | 4.54% | 4.23% | 8.76% |
| Evergy, Inc. | EVRG | Yes | Yes | $2.61 | $52.20 | $49.76 | $51.52 | $51.16 | 5.10% | 5.71% | 10.81% |
| Fortis, Inc. | FTS | | Yes | $2.53 | $41.13 | $40.13 | $38.58 | $39.95 | 6.33% | 5.31% | 11.65% |
| IDACORP, Inc. | IDA | Yes | Yes | $3.40 | $98.32 | $92.57 | $94.25 | $95.05 | 3.58% | 6.28% | 9.86% |
| NextEra Energy, Inc. | NEE | Yes | | $2.06 | $60.74 | $58.63 | $55.19 | $58.19 | 3.54% | 6.53% | 10.07% |
| NorthWestern Corporation | NWE | Yes | Yes | $2.60 | $50.89 | $47.79 | $48.47 | $49.05 | 5.30% | 1.89% | 7.19% |
| OGE Energy Corporation | OGE | Yes | Yes | $1.78 | $34.93 | $32.89 | $33.62 | $33.81 | 5.26% | 2.35% | 7.62% |
| Pinnacle West Capital Corporation | PNW | Yes | Yes | $3.54 | $71.84 | $71.37 | $69.92 | $71.04 | 4.98% | 2.12% | 7.10% |
| Portland General Electric Company | POR | Yes | Yes | $1.98 | $43.34 | $40.93 | $40.11 | $41.46 | 4.78% | 5.96% | 10.74% |
| PPL Corporation | PPL | | Yes | $1.03 | $27.10 | $26.20 | $26.37 | $26.56 | 3.88% | -2.43% | 1.44% |
| Public Service Enterprise Group Inc. | PEG | | Yes | $2.40 | $61.15 | $57.67 | $58.44 | $59.09 | 4.06% | 5.43% | 9.49% |
| Sempra Energy | SRE | | Yes | $2.50 | $74.73 | $70.91 | $72.01 | $72.55 | 3.45% | -2.60% | 0.85% |
| Southern Company | SO | Yes | | $2.86 | $70.12 | $69.11 | $70.17 | $69.80 | 4.10% | 2.84% | 6.94% |
| Wisconsin Energy Corporation | WEC | | Yes | $3.33 | $84.17 | $79.87 | $81.65 | $81.90 | 4.07% | 5.75% | 9.82% |
| Xcel Energy Inc. | XEL | Yes | | $2.22 | $61.91 | $59.39 | $60.86 | $60.72 | 3.66% | 6.67% | 10.32% |
| Company Proxy Group - Mean | | 16 | | | | | | | | | 9.03% |
| Staff Proxy Group - Mean | | | 16 | | | | | | | | 8.40% |

Notes
[1] Source: Value Line Reports dated: October 20, 2023, November 10, 2023, and December 8, 2023
[2] Source: Staff/102 Muldoon/5
[3] Source: Staff/102 Muldoon/5
[4] Source: Staff/102 Muldoon/5
[5] Equals Average ([2], [3], [4])
[6] Equals [1] / [6]
[7] Source: Value Line Reports dated: October 20, 2023, November 10, 2023, and December 8, 2023
[8] Equals [6] + [7]

STAFF CONSTANT GROWTH DCF -- PROJECTED EARNINGS AND DIVIDEND GROWTH RATES & EXCLUDE NEGATIVE GROWTH RATES

| Company | Ticker | Company Proxy Group | Staff Proxy Group | [1] Value Line Annual Dividend (2024) | [2] Stock Price at 12/1/2023 | [3] Stock Price at 1/1/2024 | [4] Stock Price at 2/1/2024 | [5] Average Stock Price | [6] Expected Dividend Yield | [7] Value Line Dividend Growth | [8] Value Line Earnings Growth | [9] Yahoo! Finance Earnings Growth | [10] Zacks Earnings Growth | [11] Average Growth Rate | [12] ROE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Alliant Energy Corporation | LNT | Yes | Yes | $1.92 | $51.30 | $48.85 | $48.97 | $49.71 | 3.86% | 6.01% | 6.50% | 6.65% | 6.30% | 6.37% | 10.23% |
| Ameren Corporation | AEE | Yes | Yes | $2.65 | $72.34 | $69.51 | $70.26 | $70.70 | 3.75% | 7.10% | 6.50% | 5.40% | 6.20% | 6.30% | 10.05% |
| American Electric Power Company, Inc. | AEP | Yes | | $3.52 | $81.22 | $77.84 | $78.65 | $79.24 | 4.44% | 5.58% | 6.50% | 3.70% | 4.80% | 5.14% | 9.59% |
| Avista Corporation | AVA | Yes | Yes | $1.92 | $35.74 | $33.78 | $33.82 | $34.45 | 5.57% | 4.49% | 6.00% | 5.90% | 5.90% | 5.57% | 11.15% |
| Black Hills Corporation | BKH | | Yes | $2.65 | $53.95 | $50.80 | $51.81 | $52.19 | 5.08% | 4.66% | 3.00% | negative | 2.20% | 3.29% | 8.36% |
| CMS Energy Corporation | CMS | Yes | | $2.04 | $58.07 | $56.39 | $58.09 | $57.52 | 3.55% | 4.79% | 5.50% | 7.70% | 7.50% | 6.37% | 9.92% |
| Consolidated Edison, Inc. | ED | | Yes | $3.34 | $90.97 | $90.02 | $91.82 | $90.94 | 3.67% | 3.68% | 6.00% | 5.66% | 2.00% | 4.34% | 8.01% |
| Duke Energy Corporation | DUK | Yes | | $4.14 | $97.04 | $95.87 | $97.13 | $96.68 | 4.28% | 1.64% | 5.00% | 6.70% | 6.10% | 4.86% | 9.14% |
| Entergy Corporation | ETR | Yes | | $4.56 | $101.19 | $99.31 | $101.10 | $100.53 | 4.54% | 4.23% | 0.50% | 11.00% | 6.40% | 5.53% | 10.07% |
| Evergy, Inc. | EVRG | Yes | Yes | $2.61 | $52.20 | $49.76 | $51.52 | $51.16 | 5.10% | 5.71% | 7.50% | 2.50% | 4.30% | 5.00% | 10.10% |
| Fortis, Inc. | FTS | | Yes | $2.53 | $41.13 | $40.13 | $38.58 | $39.95 | 6.33% | 5.31% | 5.00% | N/A | N/A | 5.16% | 11.49% |
| IDACORP, Inc. | IDA | Yes | Yes | $3.40 | $98.32 | $92.57 | $94.25 | $95.05 | 3.58% | 6.28% | 4.00% | 3.70% | 4.10% | 4.52% | 8.10% |
| NextEra Energy, Inc. | NEE | Yes | | $2.06 | $60.74 | $58.63 | $55.19 | $58.19 | 3.54% | 6.53% | 9.50% | 8.15% | 8.20% | 8.09% | 11.63% |
| NorthWestern Corporation | NWE | Yes | Yes | $2.60 | $50.89 | $47.79 | $48.47 | $49.05 | 5.30% | 1.89% | 3.50% | 4.08% | 5.20% | 3.67% | 8.97% |
| OGE Energy Corporation | OGE | Yes | Yes | $1.78 | $34.93 | $32.89 | $33.62 | $33.81 | 5.26% | 2.35% | 6.50% | negative | 3.70% | 4.18% | 9.45% |
| Pinnacle West Capital Corporation | PNW | Yes | Yes | $3.54 | $71.84 | $71.37 | $69.92 | $71.04 | 4.98% | 2.12% | 2.50% | 5.90% | 5.90% | 4.11% | 9.09% |
| Portland General Electric Company | POR | Yes | Yes | $1.98 | $43.34 | $40.93 | $40.11 | $41.46 | 4.78% | 5.96% | 5.00% | 4.60% | 6.00% | 5.39% | 10.17% |
| PPL Corporation | PPL | | Yes | $1.03 | $27.10 | $26.20 | $26.37 | $26.56 | 3.88% | negative | 8.00% | Outlier | 7.40% | 7.70% | 11.58% |
| Public Service Enterprise Group Inc. | PEG | | Yes | $2.40 | $61.15 | $57.67 | $58.44 | $59.09 | 4.06% | 5.43% | 4.00% | 5.20% | 4.90% | 4.88% | 8.94% |
| Sempra Energy | SRE | | Yes | $2.50 | $74.73 | $70.91 | $72.01 | $72.55 | 3.45% | negative | 6.50% | 4.14% | 5.00% | 5.21% | 8.66% |
| Southern Company | SO | Yes | | $2.86 | $70.12 | $69.11 | $70.17 | $69.80 | 4.10% | 2.84% | 6.50% | 7.10% | 4.00% | 5.11% | 9.21% |
| Wisconsin Energy Corporation | WEC | | Yes | $3.33 | $84.17 | $79.87 | $81.65 | $81.90 | 4.07% | 5.75% | 6.00% | 5.45% | 5.90% | 5.78% | 9.84% |
| Xcel Energy Inc. | XEL | Yes | | $2.22 | $61.91 | $59.39 | $60.86 | $60.72 | 3.66% | 6.67% | 6.00% | 6.30% | 6.00% | 6.24% | 9.90% |
| Company Proxy Group - Mean | | 16 | | | | | | | | | | | | | 9.80% |
| Staff Proxy Group - Mean | | | 16 | | | | | | | | | | | | 9.64% |

Notes
[1] Source: Value Line Reports dated: October 20, 2023, November 10, 2023, and December 8, 2023
[2] Source: Staff/102 Muldoon/5
[3] Source: Staff/102 Muldoon/5
[4] Source: Staff/102 Muldoon/5
[5] Equals Average ([2], [3], [4])
[6] Equals [1] / [6]
[7] Source: Value Line Reports dated: October 20, 2023, November 10, 2023, and December 8, 2023
[8] Source: Value Line Reports dated: October 20, 2023, November 10, 2023, and December 8, 2023
[9] Source: Yahoo! Finance as of 12/31/2023
[10] Source: Zacks as of 12/31/2023
[11] Equals Average ([7], [8], [9],[10])
[12] Equals [6] + [11]
[13] PPL's projected EPS growth rate of 17.21 percent as reported by Yahoo! was considered an outlier and excluded from the analysis.
[14] Ms. Bulkley did not has access to the projected EPS growth rates from Yahoo! and Zacks for FTS and therefore, only relied on the projected EPS and DPS growth rates from Value Line for FTS.

Docket No. UE 433
Exhibit PAC/2211
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Revision to Staff Hamanda Adjustment**

**July 2024**

STAFF HAMADA ADJUSTMENT - AS FILED

| Company | Ticker | Company Proxy Group | Staff Proxy Group | [1] Value Line Cap Structure Percentages (2024) LT Debt | [2] Value Line Cap Structure Percentages (2024) Common Equity | [3] Value Line Cap Structure Percentages (2024) Preferred Stock | [4] Value Line Beta | [5] Value Line 2023 Tax Rate | [6] 2024 Unlevered Beta | [7] 2024 Relevered Beta - Debt at 50.00% | [8] Equity Risk Premium | [9] Hamada 2024 Adjustment - Debt at 50.00% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Alliant Energy Corporation | LNT | Yes | Yes | 52.50 | 47.50 | 0.00 | 0.90 | 2.0% | 0.43 | 0.86 | 4.50% | -0.20% |
| Ameren Corporation | AEE | Yes | Yes | 53.50 | 46.00 | 0.50 | 0.90 | 12.0% | 0.44 | 0.83 | 4.50% | -0.30% |
| American Electric Power Company, Inc. | AEP | Yes | | 58.00 | 42.00 | 0.00 | 0.80 | 21.0% | 0.38 | 0.68 | 4.50% | -0.52% |
| Avista Corporation | AVA | Yes | Yes | 50.50 | 49.50 | 0.00 | 0.90 | 15.0% | 0.48 | 0.89 | 4.50% | -0.04% |
| Black Hills Corporation | BKH | | Yes | 55.50 | 45.50 | -1.00 | 1.00 | 8.5% | 0.48 | 0.91 | 4.50% | -0.39% |
| CMS Energy Corporation | CMS | Yes | | 64.00 | 35.00 | 1.00 | 0.85 | 15.0% | 0.33 | 0.61 | 4.50% | -1.08% |
| Consolidated Edison, Inc. | ED | | Yes | 48.00 | 52.00 | 0.00 | 0.75 | 18.0% | 0.43 | 0.78 | 4.50% | 0.12% |
| Duke Energy Corporation | DUK | Yes | | 58.50 | 40.00 | 1.50 | 0.85 | 9.0% | 0.36 | 0.69 | 4.50% | -0.74% |
| Entergy Corporation | ETR | Yes | | 64.50 | 35.50 | 0.00 | 0.95 | 23.0% | 0.40 | 0.70 | 4.50% | -1.12% |
| Evergy, Inc. | EVRG | Yes | Yes | 51.50 | 48.50 | 0.00 | 0.95 | 9.0% | 0.48 | 0.92 | 4.50% | -0.12% |
| Fortis, Inc. | FTS | | Yes | 53.00 | 43.50 | 3.50 | 0.70 | 14.5% | 0.33 | 0.62 | 4.50% | -0.38% |
| IDACORP, Inc. | IDA | Yes | Yes | 47.00 | 53.00 | 0.00 | 0.85 | 13.0% | 0.48 | 0.90 | 4.50% | 0.21% |
| NextEra Energy, Inc. | NEE | Yes | | 59.00 | 41.00 | 0.00 | 0.95 | 18.0% | 0.44 | 0.79 | 4.50% | -0.71% |
| NorthWestern Corporation | NWE | Yes | Yes | 46.50 | 53.50 | 0.00 | 0.95 | 6.0% | 0.52 | 1.01 | 4.50% | 0.29% |
| OGE Energy Corporation | OGE | Yes | Yes | 52.00 | 48.00 | 0.00 | 1.05 | 12.0% | 0.54 | 1.01 | 4.50% | -0.18% |
| Pinnacle West Capital Corporation | PNW | Yes | Yes | 52.50 | 47.50 | 0.00 | 0.95 | 12.0% | 0.48 | 0.91 | 4.50% | -0.20% |
| Portland General Electric Company | POR | Yes | Yes | 53.50 | 46.50 | 0.00 | 0.90 | 17.5% | 0.46 | 0.84 | 4.50% | -0.26% |
| PPL Corporation | PPL | | Yes | 46.50 | 53.50 | 0.00 | 1.05 | 21.0% | 0.62 | 1.11 | 4.50% | 0.29% |
| Public Service Enterprise Group Inc. | PEG | | Yes | 53.50 | 46.50 | 0.00 | 0.90 | 20.0% | 0.47 | 0.84 | 4.50% | -0.25% |
| Sempra Energy | SRE | | Yes | 49.00 | 49.50 | 1.50 | 1.00 | 19.0% | 0.55 | 0.99 | 4.50% | -0.04% |
| Southern Company | SO | Yes | | 64.00 | 36.00 | 0.00 | 0.90 | 15.0% | 0.36 | 0.66 | 4.50% | -1.07% |
| Wisconsin Energy Corporation | WEC | | Yes | 55.00 | 44.50 | 0.50 | 0.85 | 19.0% | 0.42 | 0.77 | 4.50% | -0.38% |
| Xcel Energy Inc. | XEL | Yes | | 58.00 | 42.00 | 0.00 | 0.85 | 0.0% | 0.36 | 0.71 | 4.50% | -0.61% |
| Company Proxy Group - Mean | | 16 | | 55.34% | 44.47% | 0.19% | | | | | | -0.41% |
| Staff Proxy Group - Mean | | | 16 | 51.25% | 48.44% | 0.31% | | | | | | -0.11% |

Notes
[1] Source: Value Line Reports dated: October 20, 2023, November 10, 2023, and December 8, 2023
[2] Source: Value Line Reports dated: October 20, 2023, November 10, 2023, and December 8, 2023
[3] Equals 100% - [1] - [2]
[4] Source: Value Line Reports dated: October 20, 2023, November 10, 2023, and December 8, 2023
[5] Source: Value Line Reports dated: October 20, 2023, November 10, 2023, and December 8, 2023
[6] Equals [4] / (1 + (1 - [5]) x (([1] + [3]) / [2]))
[7] Equals [6] x (1 + (1 - [5]) x (50.00% / (1 - 50.00%)))
[8] Source: Staff/102 Muldoon/5
[9] Equals [8] x ([7] - [4])

STAFF HAMADA ADJUSTMENT - ADJUSTED MARKET VALUE OF DEBT AND EQUITY & EQUITY RISK PREMIUM

| | | | | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | S&P Capital IQ | | | | | | | | |
| | | Company | | Cap Structure Percentages (Market Value) | | | | Value Line | | Relevered Beta - Debt at | | Hamada Adjustment - Debt at |
| Company | Ticker | Proxy Group | Staff Proxy Group | LT Debt | Common Equity | Preferred Stock | Value Line Beta | 2023 Tax Rate | Unlevered Beta | 50.00% | Equity Risk Premium | 50.00% |
| Alliant Energy Corporation | LNT | Yes | Yes | 40.99 | 59.01 | 0.00 | 0.90 | 2.0% | 0.54 | 1.06 | 4.73% | 0.76% |
| Ameren Corporation | AEE | Yes | Yes | 44.33 | 55.67 | 0.00 | 0.90 | 12.0% | 0.53 | 0.99 | 4.73% | 0.45% |
| American Electric Power Company, Inc. | AEP | Yes | | 49.01 | 50.99 | 0.00 | 0.80 | 21.0% | 0.45 | 0.81 | 4.73% | 0.07% |
| Avista Corporation | AVA | Yes | Yes | 46.30 | 53.70 | 0.00 | 0.90 | 15.0% | 0.52 | 0.96 | 4.73% | 0.29% |
| Black Hills Corporation | BKH | | Yes | 53.47 | 46.53 | 0.00 | 1.00 | 8.5% | 0.49 | 0.93 | 4.73% | -0.31% |
| CMS Energy Corporation | CMS | Yes | | 45.61 | 53.68 | 0.71 | 0.85 | 15.0% | 0.49 | 0.91 | 4.73% | 0.27% |
| Consolidated Edison, Inc. | ED | | Yes | 40.16 | 59.84 | 0.00 | 0.75 | 18.0% | 0.48 | 0.88 | 4.73% | 0.62% |
| Duke Energy Corporation | DUK | Yes | | 48.55 | 50.14 | 1.32 | 0.85 | 9.0% | 0.45 | 0.85 | 4.73% | 0.01% |
| Entergy Corporation | ETR | Yes | | 52.17 | 47.83 | 0.00 | 0.95 | 23.0% | 0.52 | 0.91 | 4.73% | -0.17% |
| Evergy, Inc. | EVRG | Yes | Yes | 50.16 | 49.84 | 0.00 | 0.95 | 9.0% | 0.50 | 0.95 | 4.73% | -0.01% |
| Fortis, Inc. | FTS | | Yes | 49.89 | 47.23 | 2.88 | 0.70 | 14.5% | 0.36 | 0.66 | 4.73% | -0.17% |
| IDACORP, Inc. | IDA | Yes | Yes | 35.04 | 64.96 | 0.00 | 0.85 | 13.0% | 0.58 | 1.08 | 4.73% | 1.10% |
| NextEra Energy, Inc. | NEE | Yes | | 35.92 | 64.08 | 0.00 | 0.95 | 18.0% | 0.65 | 1.18 | 4.73% | 1.11% |
| NorthWestern Corporation | NWE | Yes | Yes | 44.80 | 55.20 | 0.00 | 0.95 | 6.0% | 0.54 | 1.05 | 4.73% | 0.45% |
| OGE Energy Corporation | OGE | Yes | Yes | 39.40 | 60.60 | 0.00 | 1.05 | 12.0% | 0.67 | 1.26 | 4.73% | 0.97% |
| Pinnacle West Capital Corporation | PNW | Yes | Yes | 51.93 | 48.07 | 0.00 | 0.95 | 12.0% | 0.49 | 0.92 | 4.73% | -0.16% |
| Portland General Electric Company | POR | Yes | Yes | 48.46 | 51.54 | 0.00 | 0.90 | 17.5% | 0.51 | 0.93 | 4.73% | 0.12% |
| PPL Corporation | PPL | | Yes | 42.18 | 57.82 | 0.00 | 1.05 | 21.0% | 0.67 | 1.19 | 4.73% | 0.67% |
| Public Service Enterprise Group Inc. | PEG | | Yes | 37.53 | 62.47 | 0.00 | 0.90 | 20.0% | 0.61 | 1.09 | 4.73% | 0.92% |
| Sempra Energy | SRE | | Yes | 38.43 | 60.43 | 1.14 | 1.00 | 19.0% | 0.65 | 1.18 | 4.73% | 0.86% |
| Southern Company | SO | Yes | | 42.85 | 57.15 | 0.00 | 0.90 | 15.0% | 0.55 | 1.02 | 4.73% | 0.55% |
| Wisconsin Energy Corporation | WEC | | Yes | 38.76 | 61.24 | 0.00 | 0.85 | 19.0% | 0.56 | 1.02 | 4.73% | 0.79% |
| Xcel Energy Inc. | XEL | Yes | | 42.31 | 57.69 | 0.00 | 0.85 | 0.0% | 0.49 | 0.98 | 4.73% | 0.62% |
| Company Proxy Group - Mean | | 16 | | 44.87% | 55.01% | 0.13% | | | | | | 0.40% |
| Staff Proxy Group - Mean | | | 16 | 43.86% | 55.88% | 0.25% | | | | | | 0.46% |

Notes
[1] Source: Exhibit PAC/2215
[2] Source: Exhibit PAC/2215
[3] Source: Exhibit PAC/2215
[4] Source: Value Line Reports dated: October 20, 2023, November 10, 2023, and December 8, 2023
[5] Source: Value Line Reports dated: October 20, 2023, November 10, 2023, and December 8, 2023
[6] Equals [4] / (1 + (1 - [5]) x (([1] + [3]) / [2]))
[7] Equals [6] x (1 + (1 - [5]) x (50.00% / (1 - 50.00%)))
[8] Source: Staff/105 Muldoon/1
[9] Equals [8] x ([7] - [4])

Docket No. UE 433
Exhibit PAC/2212
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Revised Staff Multi-Stage DCF Analysis (Model X)**

**July 2024**

| Stage 3 – Long-Term Annual Dividend and EPS Growth Rates | | |
|---|---|---|
| SSA | 4.39% | 1 |
| CBO | 4.46% | 2 |
| Composite | 4.58% | 3 |
| BEA Nominal Historical | 5.10% | 4 |
| Bulkley Growth Rate | 5.51% | 5 |

| GDP GROWTH RATE INPUT | 3 |
|---|---|

**Average B.O.Y. & E.O.Y. Cash Flows**

| Company | Ticker | Company Proxy Group | Staff Proxy Group | Average IRR | Terminal Value as % of $NPV_{DIV}$ |
|---|---|---|---|---|---|
| Alliant Energy Corporation | LNT | Yes | Yes | 8.8% | 32.3% |
| Ameren Corporation | AEE | Yes | Yes | 9.0% | 31.4% |
| American Electric Power Company, Inc. | AEP | Yes | | 9.4% | 27.9% |
| Avista Corporation | AVA | Yes | Yes | 10.3% | 21.7% |
| Black Hills Corporation | BKH | | Yes | 9.8% | 25.0% |
| CMS Energy Corporation | CMS | Yes | | 8.2% | 37.8% |
| Consolidated Edison, Inc. | ED | | Yes | 8.4% | 36.0% |
| Duke Energy Corporation | DUK | Yes | | 8.4% | 35.1% |
| Entergy Corporation | ETR | Yes | | 9.0% | 30.3% |
| Evergy, Inc. | EVRG | Yes | Yes | 10.0% | 23.6% |
| Fortis, Inc. | FTS | | Yes | 10.9% | 18.7% |
| IDACORP, Inc. | IDA | Yes | Yes | 8.6% | 34.1% |
| NextEra Energy, Inc. | NEE | Yes | | 8.1% | 38.4% |
| NorthWestern Corporation | NWE | Yes | Yes | 9.4% | 26.6% |
| OGE Energy Corporation | OGE | Yes | Yes | 9.3% | 27.5% |
| Pinnacle West Capital Corporation | PNW | Yes | Yes | 9.1% | 28.8% |
| Portland General Electric Company | POR | Yes | Yes | 9.8% | 25.1% |
| PPL Corporation | PPL | | Yes | 8.6% | 33.9% |
| Public Service Enterprise Group Inc. | PEG | | Yes | 8.9% | 31.3% |
| Sempra Energy | SRE | | Yes | 8.1% | 38.3% |
| Southern Company | SO | Yes | | 8.5% | 34.7% |
| Wisconsin Energy Corporation | WEC | | Yes | 8.8% | 32.2% |
| Xcel Energy Inc. | XEL | Yes | | 8.7% | 33.9% |
| Company Proxy Group - Mean | | 16 | | 9.04% | 30.58% |
| Staff Proxy Group - Mean | | | 16 | 9.24% | 29.16% |

**E.O.Y. Cash Flows**

| [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] | [13] | [14] | [15] | [16] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | Company Proxy Group | Staff Proxy Group | | 2020 | 2021 | 2022 | 2020-2022 | 2026-2028 | Growth Rate (2020-22 - 2026-28) | GDP Growth Rate | IRR | Terminal Value as % of $NPV_{DIV}$ | NPV @ IRR | Recent Price* |
| Alliant Energy Corporation | LNT | Yes | Yes | Annualized DPS | 1.52 | 1.61 | 1.71 | 1.61 | 2.29 | 6.0% | 4.58% | 8.7% | 33.3% | 0.00 | (49.71) |
| Ameren Corporation | AEE | Yes | Yes | Annualized DPS | 2.00 | 2.20 | 2.36 | 2.19 | 3.30 | 7.1% | 4.58% | 8.8% | 32.4% | 0.00 | (70.70) |
| American Electric Power Company, Inc. | AEP | Yes | | Annualized DPS | 2.84 | 3.00 | 3.17 | 3.00 | 4.16 | 5.6% | 4.58% | 9.3% | 28.8% | 0.00 | (79.24) |
| Avista Corporation | AVA | Yes | Yes | Annualized DPS | 1.62 | 1.69 | 1.76 | 1.69 | 2.20 | 4.5% | 4.58% | 10.2% | 22.5% | 0.00 | (34.45) |
| Black Hills Corporation | BKH | | Yes | Annualized DPS | 2.17 | 2.29 | 2.41 | 2.29 | 3.01 | 4.7% | 4.58% | 9.6% | 25.8% | 0.00 | (52.19) |
| CMS Energy Corporation | CMS | Yes | | Annualized DPS | 1.63 | 1.74 | 1.84 | 1.74 | 2.30 | 4.8% | 4.58% | 8.1% | 38.7% | 0.00 | (57.52) |
| Consolidated Edison, Inc. | ED | | Yes | Annualized DPS | 3.06 | 3.10 | 3.16 | 3.11 | 3.86 | 3.7% | 4.58% | 8.3% | 36.8% | 0.00 | (90.94) |
| Duke Energy Corporation | DUK | Yes | | Annualized DPS | 3.82 | 3.90 | 3.98 | 3.90 | 4.30 | 1.6% | 4.58% | 8.3% | 35.8% | 0.00 | (96.68) |
| Entergy Corporation | ETR | Yes | | Annualized DPS | 3.74 | 3.86 | 4.10 | 3.90 | 5.00 | 4.2% | 4.58% | 8.905% | 31.1% | 0.00 | (100.53) |
| Evergy, Inc. | EVRG | Yes | Yes | Annualized DPS | 2.05 | 2.18 | 2.33 | 2.19 | 3.05 | 5.7% | 4.58% | 9.9% | 24.5% | 0.00 | (51.16) |
| Fortis, Inc. | FTS | | Yes | Annualized DPS | 1.94 | 2.05 | 2.17 | 2.05 | 2.80 | 5.3% | 4.58% | 10.7% | 19.5% | 0.00 | (39.95) |
| IDACORP, Inc. | IDA | Yes | Yes | Annualized DPS | 2.72 | 2.88 | 3.04 | 2.88 | 4.15 | 6.3% | 4.58% | 8.5% | 35.1% | 0.00 | (95.05) |
| NextEra Energy, Inc. | NEE | Yes | | Annualized DPS | 1.40 | 1.54 | 1.70 | 1.55 | 2.26 | 6.5% | 4.58% | 8.0% | 39.3% | 0.00 | (58.19) |
| NorthWestern Corporation | NWE | Yes | Yes | Annualized DPS | 2.40 | 2.48 | 2.52 | 2.47 | 2.76 | 1.9% | 4.58% | 9.3% | 27.3% | 0.00 | (49.05) |
| OGE Energy Corporation | OGE | Yes | Yes | Annualized DPS | 1.57 | 1.62 | 1.64 | 1.61 | 1.85 | 2.4% | 4.58% | 9.2% | 28.2% | 0.00 | (33.81) |
| Pinnacle West Capital Corporation | PNW | Yes | Yes | Annualized DPS | 3.18 | 3.34 | 3.40 | 3.31 | 3.75 | 2.1% | 4.58% | 9.0% | 29.4% | 0.00 | (71.04) |
| Portland General Electric Company | POR | Yes | Yes | Annualized DPS | 1.56 | 1.68 | 1.77 | 1.67 | 2.36 | 6.0% | 4.58% | 9.7% | 26.0% | 0.00 | (41.46) |
| PPL Corporation | PPL | | Yes | Annualized DPS | 1.66 | 1.66 | 1.07 | 1.46 | 1.26 | -2.4% | 4.58% | 8.5% | 34.8% | 0.00 | (26.56) |
| Public Service Enterprise Group Inc. | PEG | | Yes | Annualized DPS | 1.96 | 2.04 | 2.16 | 2.05 | 2.82 | 5.4% | 4.58% | 8.8% | 32.2% | 0.00 | (59.09) |
| Sempra Energy | SRE | | Yes | Annualized DPS | 4.10 | 4.35 | 2.27 | 3.57 | 3.05 | -2.6% | 4.58% | 8.0% | 39.2% | 0.00 | (72.55) |
| Southern Company | SO | Yes | | Annualized DPS | 2.54 | 2.62 | 2.70 | 2.62 | 3.10 | 2.8% | 4.58% | 8.4% | 35.5% | 0.00 | (69.80) |
| Wisconsin Energy Corporation | WEC | | Yes | Annualized DPS | 2.53 | 2.71 | 2.91 | 2.72 | 3.80 | 5.8% | 4.58% | 8.7% | 33.1% | 0.00 | (81.90) |
| Xcel Energy Inc. | XEL | Yes | | Annualized DPS | 1.70 | 1.80 | 1.92 | 1.81 | 2.66 | 6.7% | 4.58% | 8.6% | 34.8% | 0.00 | (60.72) |
| Company Proxy Group - Mean | | 16 | | | | | | | | | | 8.93% | 31.41% | 0.00 | |
| Staff Proxy Group - Mean | | | 16 | | | | | | | | | 9.13% | 30.00% | 0.00 | |

**B.O.Y. Cash Flows**

| [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] | [13] | [14] | [15] | [16] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | Company Proxy Group | Staff Proxy Group | | 2020 | 2021 | 2022 | 2020-2022 | 2026-2028 | Growth Rate (2020-22 - 2026-28) | GDP Growth Rate | IRR | Terminal Value as % of $NPV_{DIV}$ | NPV @ IRR | Recent Price* |
| Alliant Energy Corporation | LNT | Yes | Yes | Annualized DPS | 1.52 | 1.61 | 1.71 | 1.61 | 2.29 | 6.0% | 4.58% | 8.9% | 31.4% | 0.00 | (49.71) |
| Ameren Corporation | AEE | Yes | Yes | Annualized DPS | 2.00 | 2.20 | 2.36 | 2.19 | 3.30 | 7.1% | 4.58% | 9.1% | 30.4% | 0.00 | (70.70) |
| American Electric Power Company, Inc. | AEP | Yes | | Annualized DPS | 2.84 | 3.00 | 3.17 | 3.00 | 4.16 | 5.6% | 4.58% | 9.5% | 27.0% | 0.00 | (79.24) |
| Avista Corporation | AVA | Yes | Yes | Annualized DPS | 1.62 | 1.69 | 1.76 | 1.69 | 2.20 | 4.5% | 4.58% | 10.4% | 20.9% | 0.00 | (34.45) |
| Black Hills Corporation | BKH | | Yes | Annualized DPS | 2.17 | 2.29 | 2.41 | 2.29 | 3.01 | 4.7% | 4.58% | 9.9% | 24.2% | 0.00 | (52.19) |
| CMS Energy Corporation | CMS | Yes | | Annualized DPS | 1.63 | 1.74 | 1.84 | 1.74 | 2.30 | 4.8% | 4.58% | 8.3% | 37.0% | 0.00 | (57.52) |
| Consolidated Edison, Inc. | ED | | Yes | Annualized DPS | 3.06 | 3.10 | 3.16 | 3.11 | 3.86 | 3.7% | 4.58% | 8.5% | 35.1% | 0.00 | (90.94) |
| Duke Energy Corporation | DUK | Yes | | Annualized DPS | 3.82 | 3.90 | 3.98 | 3.90 | 4.30 | 1.6% | 4.58% | 8.5% | 34.5% | 0.00 | (96.68) |
| Entergy Corporation | ETR | Yes | | Annualized DPS | 3.74 | 3.86 | 4.10 | 3.90 | 5.00 | 4.2% | 4.58% | 9.1% | 29.5% | 0.00 | (100.53) |
| Evergy, Inc. | EVRG | Yes | Yes | Annualized DPS | 2.05 | 2.18 | 2.33 | 2.19 | 3.05 | 5.7% | 4.58% | 10.1% | 22.8% | 0.00 | (51.16) |
| Fortis, Inc. | FTS | | Yes | Annualized DPS | 1.94 | 2.05 | 2.17 | 2.05 | 2.80 | 5.3% | 4.58% | 11.0% | 17.9% | 0.00 | (39.95) |
| IDACORP, Inc. | IDA | Yes | Yes | Annualized DPS | 2.72 | 2.88 | 3.04 | 2.88 | 4.15 | 6.3% | 4.58% | 8.7% | 33.1% | 0.00 | (95.05) |
| NextEra Energy, Inc. | NEE | Yes | | Annualized DPS | 1.40 | 1.54 | 1.70 | 1.55 | 2.26 | 6.5% | 4.58% | 8.2% | 37.5% | 0.00 | (58.19) |
| NorthWestern Corporation | NWE | Yes | Yes | Annualized DPS | 2.40 | 2.48 | 2.52 | 2.47 | 2.76 | 1.9% | 4.58% | 9.5% | 26.0% | 0.00 | (49.05) |
| OGE Energy Corporation | OGE | Yes | Yes | Annualized DPS | 1.57 | 1.62 | 1.64 | 1.61 | 1.85 | 2.4% | 4.58% | 9.4% | 26.8% | 0.00 | (33.81) |
| Pinnacle West Capital Corporation | PNW | Yes | Yes | Annualized DPS | 3.18 | 3.34 | 3.40 | 3.31 | 3.75 | 2.1% | 4.58% | 9.2% | 28.1% | 0.00 | (71.04) |
| Portland General Electric Company | POR | Yes | Yes | Annualized DPS | 1.56 | 1.68 | 1.77 | 1.67 | 2.36 | 6.0% | 4.58% | 9.9% | 24.2% | 0.00 | (41.46) |
| PPL Corporation | PPL | | Yes | Annualized DPS | 1.66 | 1.66 | 1.07 | 1.46 | 1.26 | -2.4% | 4.58% | 8.6% | 33.0% | 0.00 | (26.56) |
| Public Service Enterprise Group Inc. | PEG | | Yes | Annualized DPS | 1.96 | 2.04 | 2.16 | 2.05 | 2.82 | 5.4% | 4.58% | 9.0% | 30.3% | 0.00 | (59.09) |
| Sempra Energy | SRE | | Yes | Annualized DPS | 4.10 | 4.35 | 2.27 | 3.57 | 3.05 | -2.6% | 4.58% | 8.2% | 37.5% | (0.00) | (72.55) |
| Southern Company | SO | Yes | | Annualized DPS | 2.54 | 2.62 | 2.70 | 2.62 | 3.10 | 2.8% | 4.58% | 8.5% | 34.0% | 0.00 | (69.80) |
| Wisconsin Energy Corporation | WEC | | Yes | Annualized DPS | 2.53 | 2.71 | 2.91 | 2.72 | 3.80 | 5.8% | 4.58% | 8.9% | 31.3% | 0.00 | (81.90) |
| Xcel Energy Inc. | XEL | Yes | | Annualized DPS | 1.70 | 1.80 | 1.92 | 1.81 | 2.66 | 6.7% | 4.58% | 8.7% | 32.9% | 0.00 | (60.72) |
| Company Proxy Group - Mean | | 16 | | | | | | | | | | 9.14% | 29.75% | 0.00 | |
| Staff Proxy Group - Mean | | | 16 | | | | | | | | | 9.34% | 28.32% | 0.00 | |

**E.O.Y. Cash Flows**

| [1] | [2] | [17] | [18] | [19] | [20] | [21] | [22] | [23] | [24] | [25] | [26] | [27] | [28] | [29] | [30] | [31] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
| | | Initial Stage | | | | | Transition Stage | | | | | | | | | |
| Company | Ticker | | | | | | | | | | | | | | | |
| Alliant Energy Corporation | LNT | 1.81 | 1.92 | 2.04 | 2.16 | 2.29 | 2.42 | 2.64 | 2.85 | 3.02 | 3.16 | 3.30 | 3.46 | 3.61 | 3.78 | 3.95 |
| Ameren Corporation | AEE | 2.52 | 2.65 | 2.85 | 3.07 | 3.30 | 3.53 | 3.89 | 4.21 | 4.48 | 4.68 | 4.90 | 5.12 | 5.36 | 5.60 | 5.86 |
| American Electric Power Company, Inc. | AEP | 3.35 | 3.52 | 3.72 | 3.93 | 4.16 | 4.39 | 4.78 | 5.13 | 5.44 | 5.69 | 5.95 | 6.22 | 6.51 | 6.81 | 7.12 |
| Avista Corporation | AVA | 1.84 | 1.92 | 2.01 | 2.10 | 2.20 | 2.30 | 2.48 | 2.65 | 2.81 | 2.94 | 3.07 | 3.21 | 3.36 | 3.51 | 3.67 |
| Black Hills Corporation | BKH | 2.53 | 2.65 | 2.76 | 2.88 | 3.01 | 3.14 | 3.39 | 3.63 | 3.84 | 4.01 | 4.20 | 4.39 | 4.59 | 4.80 | 5.02 |
| CMS Energy Corporation | CMS | 1.95 | 2.04 | 2.12 | 2.21 | 2.30 | 2.39 | 2.59 | 2.77 | 2.93 | 3.07 | 3.21 | 3.35 | 3.51 | 3.67 | 3.84 |
| Consolidated Edison, Inc. | ED | 3.24 | 3.34 | 3.51 | 3.68 | 3.86 | 4.04 | 4.34 | 4.62 | 4.88 | 5.10 | 5.34 | 5.58 | 5.84 | 6.10 | 6.38 |
| Duke Energy Corporation | DUK | 4.06 | 4.14 | 4.19 | 4.25 | 4.30 | 4.35 | 4.61 | 4.86 | 5.10 | 5.34 | 5.58 | 5.84 | 6.10 | 6.38 | 6.67 |
| Entergy Corporation | ETR | 4.34 | 4.56 | 4.70 | 4.85 | 5.00 | 5.15 | 5.56 | 5.93 | 6.27 | 6.56 | 6.86 | 7.17 | 7.50 | 7.84 | 8.20 |
| Evergy, Inc. | EVRG | 2.48 | 2.61 | 2.75 | 2.90 | 3.05 | 3.20 | 3.49 | 3.76 | 3.98 | 4.17 | 4.36 | 4.56 | 4.76 | 4.98 | 5.21 |
| Fortis, Inc. | FTS | 2.29 | 2.53 | 2.62 | 2.71 | 2.80 | 2.89 | 3.15 | 3.38 | 3.58 | 3.74 | 3.91 | 4.09 | 4.28 | 4.47 | 4.68 |
| IDACORP, Inc. | IDA | 3.20 | 3.40 | 3.63 | 3.88 | 4.15 | 4.42 | 4.83 | 5.21 | 5.53 | 5.79 | 6.05 | 6.33 | 6.62 | 6.92 | 7.24 |
| NextEra Energy, Inc. | NEE | 1.87 | 2.06 | 2.12 | 2.19 | 2.26 | 2.33 | 2.55 | 2.76 | 2.93 | 3.06 | 3.20 | 3.35 | 3.50 | 3.66 | 3.83 |
| NorthWestern Corporation | NWE | 2.56 | 2.60 | 2.65 | 2.71 | 2.76 | 2.81 | 2.98 | 3.15 | 3.31 | 3.46 | 3.62 | 3.79 | 3.96 | 4.14 | 4.33 |
| OGE Energy Corporation | OGE | 1.66 | 1.78 | 1.80 | 1.83 | 1.85 | 1.87 | 1.99 | 2.11 | 2.22 | 2.32 | 2.43 | 2.54 | 2.65 | 2.78 | 2.90 |
| Pinnacle West Capital Corporation | PNW | 3.48 | 3.54 | 3.61 | 3.68 | 3.75 | 3.82 | 4.06 | 4.29 | 4.51 | 4.72 | 4.93 | 5.16 | 5.39 | 5.64 | 5.90 |
| Portland General Electric Company | POR | 1.88 | 1.98 | 2.10 | 2.23 | 2.36 | 2.49 | 2.72 | 2.93 | 3.11 | 3.25 | 3.40 | 3.56 | 3.72 | 3.89 | 4.07 |
| PPL Corporation | PPL | 0.95 | 1.03 | 1.10 | 1.18 | 1.26 | 1.34 | 1.38 | 1.42 | 1.48 | 1.55 | 1.62 | 1.69 | 1.77 | 1.85 | 1.93 |
| Public Service Enterprise Group Inc. | PEG | 2.28 | 2.40 | 2.53 | 2.67 | 2.82 | 2.97 | 3.23 | 3.47 | 3.67 | 3.84 | 4.02 | 4.20 | 4.39 | 4.60 | 4.81 |
| Sempra Energy | SRE | 2.38 | 2.50 | 2.67 | 2.85 | 3.05 | 3.25 | 3.33 | 3.43 | 3.57 | 3.73 | 3.90 | 4.08 | 4.27 | 4.46 | 4.67 |
| Southern Company | SO | 2.78 | 2.86 | 2.94 | 3.02 | 3.10 | 3.18 | 3.40 | 3.60 | 3.80 | 3.97 | 4.15 | 4.34 | 4.54 | 4.75 | 4.96 |
| Wisconsin Energy Corporation | WEC | 3.12 | 3.33 | 3.48 | 3.64 | 3.80 | 3.96 | 4.32 | 4.65 | 4.93 | 5.16 | 5.39 | 5.64 | 5.90 | 6.17 | 6.45 |
| Xcel Energy Inc. | XEL | 2.08 | 2.22 | 2.36 | 2.50 | 2.66 | 2.82 | 3.09 | 3.34 | 3.55 | 3.71 | 3.88 | 4.06 | 4.24 | 4.44 | 4.64 |
| Company Proxy Group - Mean | | | | | | | | | | | | | | | | |
| Staff Proxy Group - Mean | | | | | | | | | | | | | | | | |

**B.O.Y. Cash Flows**

| [1] | [2] | [17] | [18] | [19] | [20] | [21] | [22] | [23] | [24] | [25] | [26] | [27] | [28] | [29] | [30] | [31] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
| | | Initial Stage | | | | | Transition Stage | | | | | | | | | |
| Company | Ticker | | | | | | | | | | | | | | | |
| Alliant Energy Corporation | LNT | 1.92 | 2.04 | 2.16 | 2.29 | 2.42 | 2.64 | 2.85 | 3.02 | 3.16 | 3.30 | 3.46 | 3.61 | 3.78 | 3.95 | 4.13 |
| Ameren Corporation | AEE | 2.65 | 2.85 | 3.07 | 3.30 | 3.53 | 3.89 | 4.21 | 4.48 | 4.68 | 4.90 | 5.12 | 5.36 | 5.60 | 5.86 | 6.13 |
| American Electric Power Company, Inc. | AEP | 3.52 | 3.72 | 3.93 | 4.16 | 4.39 | 4.78 | 5.13 | 5.44 | 5.69 | 5.95 | 6.22 | 6.51 | 6.81 | 7.12 | 7.44 |
| Avista Corporation | AVA | 1.92 | 2.01 | 2.10 | 2.20 | 2.30 | 2.48 | 2.65 | 2.81 | 2.94 | 3.07 | 3.21 | 3.36 | 3.51 | 3.67 | 3.84 |
| Black Hills Corporation | BKH | 2.65 | 2.76 | 2.88 | 3.01 | 3.14 | 3.39 | 3.63 | 3.84 | 4.01 | 4.20 | 4.39 | 4.59 | 4.80 | 5.02 | 5.25 |
| CMS Energy Corporation | CMS | 2.04 | 2.12 | 2.21 | 2.30 | 2.39 | 2.59 | 2.77 | 2.93 | 3.07 | 3.21 | 3.35 | 3.51 | 3.67 | 3.84 | 4.01 |
| Consolidated Edison, Inc. | ED | 3.34 | 3.51 | 3.68 | 3.86 | 4.04 | 4.34 | 4.62 | 4.88 | 5.10 | 5.34 | 5.58 | 5.84 | 6.10 | 6.38 | 6.68 |
| Duke Energy Corporation | DUK | 4.14 | 4.19 | 4.25 | 4.30 | 4.35 | 4.61 | 4.86 | 5.10 | 5.34 | 5.58 | 5.84 | 6.10 | 6.38 | 6.67 | 6.98 |
| Entergy Corporation | ETR | 4.56 | 4.70 | 4.85 | 5.00 | 5.15 | 5.56 | 5.93 | 6.27 | 6.56 | 6.86 | 7.17 | 7.50 | 7.84 | 8.20 | 8.58 |
| Evergy, Inc. | EVRG | 2.61 | 2.75 | 2.90 | 3.05 | 3.20 | 3.49 | 3.76 | 3.98 | 4.17 | 4.36 | 4.56 | 4.76 | 4.98 | 5.21 | 5.45 |
| Fortis, Inc. | FTS | 2.53 | 2.62 | 2.71 | 2.80 | 2.89 | 3.15 | 3.38 | 3.58 | 3.74 | 3.91 | 4.09 | 4.28 | 4.47 | 4.68 | 4.89 |
| IDACORP, Inc. | IDA | 3.40 | 3.63 | 3.88 | 4.15 | 4.42 | 4.83 | 5.21 | 5.53 | 5.79 | 6.05 | 6.33 | 6.62 | 6.92 | 7.24 | 7.57 |
| NextEra Energy, Inc. | NEE | 2.06 | 2.12 | 2.19 | 2.26 | 2.33 | 2.55 | 2.76 | 2.93 | 3.06 | 3.20 | 3.35 | 3.50 | 3.66 | 3.83 | 4.01 |
| NorthWestern Corporation | NWE | 2.60 | 2.65 | 2.71 | 2.76 | 2.81 | 2.98 | 3.15 | 3.31 | 3.46 | 3.62 | 3.79 | 3.96 | 4.14 | 4.33 | 4.53 |
| OGE Energy Corporation | OGE | 1.78 | 1.80 | 1.83 | 1.85 | 1.87 | 1.99 | 2.11 | 2.22 | 2.32 | 2.43 | 2.54 | 2.65 | 2.78 | 2.90 | 3.04 |
| Pinnacle West Capital Corporation | PNW | 3.54 | 3.61 | 3.68 | 3.75 | 3.82 | 4.06 | 4.29 | 4.51 | 4.72 | 4.93 | 5.16 | 5.39 | 5.64 | 5.90 | 6.17 |
| Portland General Electric Company | POR | 1.98 | 2.10 | 2.23 | 2.36 | 2.49 | 2.72 | 2.93 | 3.11 | 3.25 | 3.40 | 3.56 | 3.72 | 3.89 | 4.07 | 4.26 |
| PPL Corporation | PPL | 1.03 | 1.10 | 1.18 | 1.26 | 1.34 | 1.38 | 1.42 | 1.48 | 1.55 | 1.62 | 1.69 | 1.77 | 1.85 | 1.93 | 2.02 |
| Public Service Enterprise Group Inc. | PEG | 2.40 | 2.53 | 2.67 | 2.82 | 2.97 | 3.23 | 3.47 | 3.67 | 3.84 | 4.02 | 4.20 | 4.39 | 4.60 | 4.81 | 5.03 |
| Sempra Energy | SRE | 2.50 | 2.67 | 2.85 | 3.05 | 3.25 | 3.33 | 3.43 | 3.57 | 3.73 | 3.90 | 4.08 | 4.27 | 4.46 | 4.67 | 4.88 |
| Southern Company | SO | 2.86 | 2.94 | 3.02 | 3.10 | 3.18 | 3.40 | 3.60 | 3.80 | 3.97 | 4.15 | 4.34 | 4.54 | 4.75 | 4.96 | 5.19 |
| Wisconsin Energy Corporation | WEC | 3.33 | 3.48 | 3.64 | 3.80 | 3.96 | 4.32 | 4.65 | 4.93 | 5.16 | 5.39 | 5.64 | 5.90 | 6.17 | 6.45 | 6.74 |
| Xcel Energy Inc. | XEL | 2.22 | 2.36 | 2.50 | 2.66 | 2.82 | 3.09 | 3.34 | 3.55 | 3.71 | 3.88 | 4.06 | 4.24 | 4.44 | 4.64 | 4.85 |
| Company Proxy Group - Mean | | | | | | | | | | | | | | | | |
| Staff Proxy Group - Mean | | | | | | | | | | | | | | | | |

**E.O.Y. Cash Flows**

| [1] | [2] | [32] | [33] | [34] | [35] | [36] | [37] | [38] | [39] | [40] | [41] | [42] | [43] | [44] | [45] | [46] | [47] | [48] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 | 2048 | 2049 | 2050 | 2051 | 2052 | 2052 | 2052 |
| | | | | | | Final Stage | | | | | | | | | | Terminal | | |
| Company | Ticker | | | | | | | | | | | | | | | Value | Div | Perpetuity |
| Alliant Energy Corporation | LNT | 4.13 | 4.32 | 4.52 | 4.73 | 4.94 | 5.17 | 5.41 | 5.65 | 5.91 | 6.18 | 6.47 | 6.76 | 7.07 | 7.40 | 203.03 | 7.73 | 195.29 |
| Ameren Corporation | AEE | 6.13 | 6.41 | 6.70 | 7.01 | 7.33 | 7.66 | 8.01 | 8.38 | 8.76 | 9.16 | 9.58 | 10.02 | 10.48 | 10.96 | 292.02 | 11.46 | 280.56 |
| American Electric Power Company, Inc. | AEP | 7.44 | 7.78 | 8.14 | 8.51 | 8.90 | 9.31 | 9.74 | 10.18 | 10.65 | 11.13 | 11.64 | 12.18 | 12.73 | 13.32 | 325.12 | 13.93 | 311.20 |
| Avista Corporation | AVA | 3.84 | 4.02 | 4.20 | 4.39 | 4.59 | 4.80 | 5.02 | 5.25 | 5.49 | 5.74 | 6.01 | 6.28 | 6.57 | 6.87 | 141.58 | 7.18 | 134.39 |
| Black Hills Corporation | BKH | 5.25 | 5.49 | 5.74 | 6.01 | 6.28 | 6.57 | 6.87 | 7.18 | 7.51 | 7.86 | 8.22 | 8.59 | 8.99 | 9.40 | 212.96 | 9.83 | 203.13 |
| CMS Energy Corporation | CMS | 4.01 | 4.19 | 4.39 | 4.59 | 4.80 | 5.02 | 5.25 | 5.49 | 5.74 | 6.00 | 6.28 | 6.56 | 6.86 | 7.18 | 230.25 | 7.51 | 222.75 |
| Consolidated Edison, Inc. | ED | 6.68 | 6.98 | 7.30 | 7.64 | 7.98 | 8.35 | 8.73 | 9.13 | 9.55 | 9.99 | 10.44 | 10.92 | 11.42 | 11.94 | 364.80 | 12.49 | 352.30 |
| Duke Energy Corporation | DUK | 6.98 | 7.30 | 7.63 | 7.98 | 8.35 | 8.73 | 9.13 | 9.55 | 9.98 | 10.44 | 10.92 | 11.42 | 11.94 | 12.49 | 379.16 | 13.06 | 366.10 |
| Entergy Corporation | ETR | 8.58 | 8.97 | 9.38 | 9.81 | 10.26 | 10.73 | 11.22 | 11.73 | 12.27 | 12.83 | 13.42 | 14.03 | 14.67 | 15.34 | 403.78 | 16.05 | 387.73 |
| Evergy, Inc. | EVRG | 5.45 | 5.70 | 5.96 | 6.23 | 6.52 | 6.81 | 7.13 | 7.45 | 7.79 | 8.15 | 8.52 | 8.91 | 9.32 | 9.75 | 211.38 | 10.19 | 201.19 |
| Fortis, Inc. | FTS | 4.89 | 5.12 | 5.35 | 5.59 | 5.85 | 6.12 | 6.40 | 6.69 | 7.00 | 7.32 | 7.65 | 8.00 | 8.37 | 8.75 | 165.05 | 9.15 | 155.89 |
| IDACORP, Inc. | IDA | 7.57 | 7.92 | 8.28 | 8.66 | 9.05 | 9.47 | 9.90 | 10.36 | 10.83 | 11.33 | 11.84 | 12.39 | 12.95 | 13.55 | 388.70 | 14.17 | 374.53 |
| NextEra Energy, Inc. | NEE | 4.01 | 4.19 | 4.38 | 4.58 | 4.79 | 5.01 | 5.24 | 5.48 | 5.73 | 5.99 | 6.27 | 6.55 | 6.85 | 7.17 | 233.37 | 7.49 | 225.87 |
| NorthWestern Corporation | NWE | 4.53 | 4.74 | 4.95 | 5.18 | 5.42 | 5.66 | 5.92 | 6.19 | 6.48 | 6.77 | 7.08 | 7.41 | 7.75 | 8.10 | 194.65 | 8.47 | 186.18 |
| OGE Energy Corporation | OGE | 3.04 | 3.17 | 3.32 | 3.47 | 3.63 | 3.80 | 3.97 | 4.15 | 4.34 | 4.54 | 4.75 | 4.97 | 5.19 | 5.43 | 134.07 | 5.68 | 128.39 |
| Pinnacle West Capital Corporation | PNW | 6.17 | 6.45 | 6.75 | 7.06 | 7.38 | 7.72 | 8.07 | 8.44 | 8.83 | 9.23 | 9.65 | 10.09 | 10.56 | 11.04 | 281.48 | 11.54 | 269.93 |
| Portland General Electric Company | POR | 4.26 | 4.45 | 4.65 | 4.87 | 5.09 | 5.32 | 5.57 | 5.82 | 6.09 | 6.37 | 6.66 | 6.96 | 7.28 | 7.61 | 171.59 | 7.96 | 163.62 |
| PPL Corporation | PPL | 2.02 | 2.12 | 2.21 | 2.31 | 2.42 | 2.53 | 2.65 | 2.77 | 2.89 | 3.03 | 3.17 | 3.31 | 3.46 | 3.62 | 105.79 | 3.79 | 102.00 |
| Public Service Enterprise Group Inc. | PEG | 5.03 | 5.26 | 5.50 | 5.75 | 6.01 | 6.29 | 6.57 | 6.87 | 7.19 | 7.52 | 7.86 | 8.22 | 8.60 | 8.99 | 240.70 | 9.40 | 231.29 |
| Sempra Energy | SRE | 4.88 | 5.10 | 5.34 | 5.58 | 5.84 | 6.10 | 6.38 | 6.68 | 6.98 | 7.30 | 7.64 | 7.99 | 8.35 | 8.73 | 287.19 | 9.13 | 278.06 |
| Southern Company | SO | 5.19 | 5.43 | 5.68 | 5.94 | 6.21 | 6.49 | 6.79 | 7.10 | 7.43 | 7.77 | 8.12 | 8.49 | 8.88 | 9.29 | 276.92 | 9.72 | 267.20 |
| Wisconsin Energy Corporation | WEC | 6.74 | 7.05 | 7.38 | 7.71 | 8.07 | 8.43 | 8.82 | 9.22 | 9.65 | 10.09 | 10.55 | 11.03 | 11.54 | 12.07 | 332.08 | 12.62 | 319.46 |
| Xcel Energy Inc. | XEL | 4.85 | 5.07 | 5.31 | 5.55 | 5.80 | 6.07 | 6.35 | 6.64 | 6.94 | 7.26 | 7.59 | 7.94 | 8.30 | 8.68 | 248.07 | 9.08 | 238.99 |
| Company Proxy Group - Mean | | | | | | | | | | | | | | | | | | |
| Staff Proxy Group - Mean | | | | | | | | | | | | | | | | | | |

**B.O.Y. Cash Flows**

| [1] | [2] | [32] | [33] | [34] | [35] | [36] | [37] | [38] | [39] | [40] | [41] | [42] | [43] | [44] | [45] | [46] | [47] | [48] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 | 2048 | 2049 | 2050 | 2051 | 2052 | 2051 | 2051 |
| | | | | | | Final Stage | | | | | | | | | | Terminal | | |
| Company | Ticker | | | | | | | | | | | | | | | Value | Div | Perpetuity |
| Alliant Energy Corporation | LNT | 4.32 | 4.52 | 4.73 | 4.94 | 5.17 | 5.41 | 5.65 | 5.91 | 6.18 | 6.47 | 6.76 | 7.07 | 7.40 | 7.73 | 202.63 | 8.09 | 194.55 |
| Ameren Corporation | AEE | 6.41 | 6.70 | 7.01 | 7.33 | 7.66 | 8.01 | 8.38 | 8.76 | 9.16 | 9.58 | 10.02 | 10.48 | 10.96 | 11.46 | 291.03 | 11.99 | 279.04 |
| American Electric Power Company, Inc. | AEP | 7.78 | 8.14 | 8.51 | 8.90 | 9.31 | 9.74 | 10.18 | 10.65 | 11.13 | 11.64 | 12.18 | 12.73 | 13.32 | 13.93 | 324.70 | 14.56 | 310.14 |
| Avista Corporation | AVA | 4.02 | 4.20 | 4.39 | 4.59 | 4.80 | 5.02 | 5.25 | 5.49 | 5.74 | 6.01 | 6.28 | 6.57 | 6.87 | 7.18 | 141.67 | 7.51 | 134.16 |
| Black Hills Corporation | BKH | 5.49 | 5.74 | 6.01 | 6.28 | 6.57 | 6.87 | 7.18 | 7.51 | 7.86 | 8.22 | 8.59 | 8.99 | 9.40 | 9.83 | 213.11 | 10.28 | 202.84 |
| CMS Energy Corporation | CMS | 4.19 | 4.39 | 4.59 | 4.80 | 5.02 | 5.25 | 5.49 | 5.74 | 6.00 | 6.28 | 6.56 | 6.86 | 7.18 | 7.51 | 230.41 | 7.85 | 222.56 |
| Consolidated Edison, Inc. | ED | 6.98 | 7.30 | 7.64 | 7.98 | 8.35 | 8.73 | 9.13 | 9.55 | 9.99 | 10.44 | 10.92 | 11.42 | 11.94 | 12.49 | 365.03 | 13.06 | 351.97 |
| Duke Energy Corporation | DUK | 7.30 | 7.63 | 7.98 | 8.35 | 8.73 | 9.13 | 9.55 | 9.98 | 10.44 | 10.92 | 11.42 | 11.94 | 12.49 | 13.06 | 381.31 | 13.66 | 367.65 |
| Entergy Corporation | ETR | 8.97 | 9.38 | 9.81 | 10.26 | 10.73 | 11.22 | 11.73 | 12.27 | 12.83 | 13.42 | 14.03 | 14.67 | 15.34 | 16.05 | 404.58 | 16.78 | 387.80 |
| Evergy, Inc. | EVRG | 5.70 | 5.96 | 6.23 | 6.52 | 6.81 | 7.13 | 7.45 | 7.79 | 8.15 | 8.52 | 8.91 | 9.32 | 9.75 | 10.19 | 211.17 | 10.66 | 200.51 |
| Fortis, Inc. | FTS | 5.12 | 5.35 | 5.59 | 5.85 | 6.12 | 6.40 | 6.69 | 7.00 | 7.32 | 7.65 | 8.00 | 8.37 | 8.75 | 9.15 | 164.95 | 9.57 | 155.38 |
| IDACORP, Inc. | IDA | 7.92 | 8.28 | 8.66 | 9.05 | 9.47 | 9.90 | 10.36 | 10.83 | 11.33 | 11.84 | 12.39 | 12.95 | 13.55 | 14.17 | 387.64 | 14.81 | 372.83 |
| NextEra Energy, Inc. | NEE | 4.19 | 4.38 | 4.58 | 4.79 | 5.01 | 5.24 | 5.48 | 5.73 | 5.99 | 6.27 | 6.55 | 6.85 | 7.17 | 7.49 | 233.26 | 7.84 | 225.43 |
| NorthWestern Corporation | NWE | 4.74 | 4.95 | 5.18 | 5.42 | 5.66 | 5.92 | 6.19 | 6.48 | 6.77 | 7.08 | 7.41 | 7.75 | 8.10 | 8.47 | 195.83 | 8.86 | 186.97 |
| OGE Energy Corporation | OGE | 3.17 | 3.32 | 3.47 | 3.63 | 3.80 | 3.97 | 4.15 | 4.34 | 4.54 | 4.75 | 4.97 | 5.19 | 5.43 | 5.68 | 134.65 | 5.94 | 128.71 |
| Pinnacle West Capital Corporation | PNW | 6.45 | 6.75 | 7.06 | 7.38 | 7.72 | 8.07 | 8.44 | 8.83 | 9.23 | 9.65 | 10.09 | 10.56 | 11.04 | 11.54 | 283.07 | 12.07 | 271.00 |
| Portland General Electric Company | POR | 4.45 | 4.65 | 4.87 | 5.09 | 5.32 | 5.57 | 5.82 | 6.09 | 6.37 | 6.66 | 6.96 | 7.28 | 7.61 | 7.96 | 171.26 | 8.33 | 162.94 |
| PPL Corporation | PPL | 2.12 | 2.21 | 2.31 | 2.42 | 2.53 | 2.65 | 2.77 | 2.89 | 3.03 | 3.17 | 3.31 | 3.46 | 3.62 | 3.79 | 105.67 | 3.96 | 101.71 |
| Public Service Enterprise Group Inc. | PEG | 5.26 | 5.50 | 5.75 | 6.01 | 6.29 | 6.57 | 6.87 | 7.19 | 7.52 | 7.86 | 8.22 | 8.60 | 8.99 | 9.40 | 240.44 | 9.83 | 230.61 |
| Sempra Energy | SRE | 5.10 | 5.34 | 5.58 | 5.84 | 6.10 | 6.38 | 6.68 | 6.98 | 7.30 | 7.64 | 7.99 | 8.35 | 8.73 | 9.13 | 287.20 | 9.55 | 277.64 |
| Southern Company | SO | 5.43 | 5.68 | 5.94 | 6.21 | 6.49 | 6.79 | 7.10 | 7.43 | 7.77 | 8.12 | 8.49 | 8.88 | 9.29 | 9.72 | 277.83 | 10.16 | 267.67 |
| Wisconsin Energy Corporation | WEC | 7.05 | 7.38 | 7.71 | 8.07 | 8.43 | 8.82 | 9.22 | 9.65 | 10.09 | 10.55 | 11.03 | 11.54 | 12.07 | 12.62 | 331.89 | 13.20 | 318.69 |
| Xcel Energy Inc. | XEL | 5.07 | 5.31 | 5.55 | 5.80 | 6.07 | 6.35 | 6.64 | 6.94 | 7.26 | 7.59 | 7.94 | 8.30 | 8.68 | 9.08 | 247.47 | 9.50 | 237.98 |
| Company Proxy Group - Mean | | | | | | | | | | | | | | | | | | |
| Staff Proxy Group - Mean | | | | | | | | | | | | | | | | | | |

Docket No. UE 433
Exhibit PAC/2213
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Revised Staff Multi-Stage DCF Analysis (Model Y)**

**July 2024**

| Stage 3 – Long-Term Annual Dividend and EPS Growth Rates | | |
|---|---|---|
| SSA | 4.39% | 1 |
| CBO | 4.46% | 2 |
| Composite | 4.58% | 3 |
| BEA Nominal Historical | 5.10% | 4 |
| Bulkley Growth Rate | 5.51% | 5 |

| GDP GROWTH RATE INPUT | 3 |
|---|---|

**Average B.O.Y. & E.O.Y. Cash Flows**

| Company | Ticker | Proxy Group | Staff Proxy Group | Average IRR | Terminal Value as % of $NPV_{DIV}$ |
|---|---|---|---|---|---|
| Alliant Energy Corporation | LNT | Yes | Yes | 9.3% | 35.6% |
| Ameren Corporation | AEE | Yes | Yes | 9.2% | 33.0% |
| American Electric Power Company, Inc. | AEP | Yes | | 9.6% | 30.1% |
| Avista Corporation | AVA | Yes | Yes | 10.5% | 23.2% |
| Black Hills Corporation | BKH | | Yes | 9.8% | 25.4% |
| CMS Energy Corporation | CMS | Yes | | 8.4% | 39.3% |
| Consolidated Edison, Inc. | ED | | Yes | 8.6% | 37.9% |
| Duke Energy Corporation | DUK | Yes | | 8.6% | 37.0% |
| Entergy Corporation | ETR | Yes | | 8.8% | 28.8% |
| Evergy, Inc. | EVRG | Yes | Yes | 10.4% | 26.5% |
| Fortis, Inc. | FTS | | Yes | 11.1% | 20.7% |
| IDACORP, Inc. | IDA | Yes | Yes | 8.7% | 34.3% |
| NextEra Energy, Inc. | NEE | Yes | | 8.8% | 42.9% |
| NorthWestern Corporation | NWE | Yes | Yes | 9.5% | 27.5% |
| OGE Energy Corporation | OGE | Yes | Yes | 10.1% | 33.2% |
| Pinnacle West Capital Corporation | PNW | Yes | Yes | 9.5% | 31.6% |
| Portland General Electric Company | POR | Yes | Yes | 10.1% | 27.5% |
| PPL Corporation | PPL | | Yes | 9.1% | 37.7% |
| Public Service Enterprise Group Inc. | PEG | | Yes | 9.1% | 32.6% |
| Sempra Energy | SRE | | Yes | 8.6% | 41.7% |
| Southern Company | SO | Yes | | 9.1% | 39.3% |
| Wisconsin Energy Corporation | WEC | | Yes | 9.1% | 34.5% |
| Xcel Energy Inc. | XEL | Yes | | 8.9% | 35.9% |
| Company Proxy Group - Mean | | 16 | | 9.34% | 32.85% |
| Staff Proxy Group - Mean | | | 16 | 9.54% | 31.43% |

**E.O.Y. Cash Flows**

| [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] | [13] | [14] | [15] | [16] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | Proxy Group | Staff Proxy Group | | 2020 | 2021 | 2022 | 2020-2022 | 2026-2028 | (2020-22 - 2026-28) | GDP Growth Rate | IRR | Terminal Value as % of $NPV_{DIV}$ | NPV @ IRR | Recent Price* |
| Alliant Energy Corporation | LNT | Yes | Yes | Annualized DPS | 1.52 | 1.61 | 1.71 | 1.61 | 2.29 | 6.0% | 4.58% | 9.2% | 36.5% | 0.00 | (49.71) |
| | | | | Annualized EPS | 2.46 | 2.62 | 2.73 | 2.60 | 3.80 | 6.5% | 4.58% | | | | |
| Ameren Corporation | AEE | Yes | Yes | Annualized DPS | 2.00 | 2.20 | 2.36 | 2.19 | 3.30 | 7.1% | 4.58% | 9.0% | 34.0% | 0.00 | (70.70) |
| | | | | Annualized EPS | 3.50 | 3.84 | 4.14 | 3.83 | 5.50 | 6.2% | 4.58% | | | | |
| American Electric Power Company, Inc. | AEP | Yes | | Annualized DPS | 2.84 | 3.00 | 3.17 | 3.00 | 4.16 | 5.6% | 4.58% | 9.5% | 31.0% | 0.00 | (79.24) |
| | | | | Annualized EPS | 4.42 | 4.96 | 5.09 | 4.82 | 6.80 | 5.9% | 4.58% | | | | |
| Avista Corporation | AVA | Yes | Yes | Annualized DPS | 1.62 | 1.69 | 1.76 | 1.69 | 2.20 | 4.5% | 4.58% | 10.4% | 24.0% | 0.00 | (34.45) |
| | | | | Annualized EPS | 1.90 | 2.09 | 2.12 | 2.04 | 2.90 | 6.1% | 4.58% | | | | |
| Black Hills Corporation | BKH | | Yes | Annualized DPS | 2.17 | 2.29 | 2.41 | 2.29 | 3.01 | 4.7% | 4.58% | 9.7% | 26.2% | 0.00 | (52.19) |
| | | | | Annualized EPS | 3.73 | 3.75 | 3.99 | 3.82 | 4.50 | 2.8% | 4.58% | | | | |
| CMS Energy Corporation | CMS | Yes | | Annualized DPS | 1.63 | 1.74 | 1.84 | 1.74 | 2.30 | 4.8% | 4.58% | 8.3% | 40.1% | 0.00 | (57.52) |
| | | | | Annualized EPS | 2.64 | 2.58 | 2.84 | 2.69 | 3.75 | 5.7% | 4.58% | | | | |
| Consolidated Edison, Inc. | ED | | Yes | Annualized DPS | 3.06 | 3.10 | 3.16 | 3.11 | 3.86 | 3.7% | 4.58% | 8.6% | 38.8% | 0.00 | (90.94) |
| | | | | Annualized EPS | 4.17 | 4.38 | 4.55 | 4.37 | 6.15 | 5.9% | 4.58% | | | | |
| Duke Energy Corporation | DUK | Yes | | Annualized DPS | 3.82 | 3.90 | 3.98 | 3.90 | 4.30 | 1.6% | 4.58% | 8.6% | 37.7% | 0.00 | (96.68) |
| | | | | Annualized EPS | 5.12 | 5.23 | 5.33 | 5.23 | 7.00 | 5.0% | 4.58% | | | | |
| Entergy Corporation | ETR | Yes | | Annualized DPS | 3.74 | 3.86 | 4.10 | 3.90 | 5.00 | 4.2% | 4.58% | 8.7% | 29.5% | 0.00 | (100.53) |
| | | | | Annualized EPS | 6.90 | 6.87 | 5.39 | 6.39 | 7.50 | 2.7% | 4.58% | | | | |
| Evergy, Inc. | EVRG | Yes | Yes | Annualized DPS | 2.05 | 2.18 | 2.33 | 2.19 | 3.05 | 5.7% | 4.58% | 10.2% | 27.3% | 0.00 | (51.16) |
| | | | | Annualized EPS | 2.72 | 3.83 | 3.26 | 3.27 | 4.85 | 6.8% | 4.58% | | | | |
| Fortis, Inc. | FTS | | Yes | Annualized DPS | 1.94 | 2.05 | 2.17 | 2.05 | 2.80 | 5.3% | 4.58% | 11.0% | 21.5% | (0.00) | (39.95) |
| | | | | Annualized EPS | 2.60 | 2.61 | 2.78 | 2.66 | 3.75 | 5.9% | 4.58% | | | | |
| IDACORP, Inc. | IDA | Yes | Yes | Annualized DPS | 2.72 | 2.88 | 3.04 | 2.88 | 4.15 | 6.3% | 4.58% | 8.6% | 35.2% | 0.00 | (95.05) |
| | | | | Annualized EPS | 4.69 | 4.85 | 5.11 | 4.88 | 6.10 | 3.8% | 4.58% | | | | |
| NextEra Energy, Inc. | NEE | Yes | | Annualized DPS | 1.40 | 1.54 | 1.70 | 1.55 | 2.26 | 6.5% | 4.58% | 8.7% | 43.7% | 0.00 | (58.19) |
| | | | | Annualized EPS | 2.31 | 2.54 | 2.91 | 2.59 | 4.40 | 9.3% | 4.58% | | | | |
| NorthWestern Corporation | NWE | Yes | Yes | Annualized DPS | 2.40 | 2.48 | 2.52 | 2.47 | 2.76 | 1.9% | 4.58% | 9.5% | 28.2% | 0.00 | (49.05) |
| | | | | Annualized EPS | 3.22 | 3.50 | 3.29 | 3.34 | 4.15 | 3.7% | 4.58% | | | | |
| OGE Energy Corporation | OGE | Yes | Yes | Annualized DPS | 1.57 | 1.62 | 1.64 | 1.61 | 1.85 | 2.4% | 4.58% | 10.0% | 34.0% | 0.00 | (33.81) |
| | | | | Annualized EPS | 2.08 | 2.35 | 2.25 | 2.23 | 3.15 | 6.0% | 4.58% | | | | |
| Pinnacle West Capital Corporation | PNW | Yes | Yes | Annualized DPS | 3.18 | 3.34 | 3.40 | 3.31 | 3.75 | 2.1% | 4.58% | 9.4% | 32.3% | 0.00 | (71.04) |
| | | | | Annualized EPS | 4.88 | 5.47 | 4.27 | 4.87 | 5.70 | 2.6% | 4.58% | | | | |
| Portland General Electric Company | POR | Yes | Yes | Annualized DPS | 1.56 | 1.68 | 1.77 | 1.67 | 2.36 | 6.0% | 4.58% | 10.0% | 28.4% | 0.00 | (41.46) |
| | | | | Annualized EPS | 2.75 | 2.72 | 2.74 | 2.74 | 3.65 | 4.9% | 4.58% | | | | |
| PPL Corporation | PPL | | Yes | Annualized DPS | 1.66 | 1.66 | 1.07 | 1.46 | 1.26 | -2.4% | 4.58% | 9.0% | 38.7% | 0.00 | (26.56) |
| | | | | Annualized EPS | 2.05 | 0.52 | 1.40 | 1.32 | 2.10 | 8.0% | 4.58% | | | | |
| Public Service Enterprise Group Inc. | PEG | | Yes | Annualized DPS | 1.96 | 2.04 | 2.16 | 2.05 | 2.82 | 5.4% | 4.58% | 9.0% | 33.5% | 0.00 | (59.09) |
| | | | | Annualized EPS | 3.43 | 3.63 | 3.47 | 3.51 | 4.40 | 3.8% | 4.58% | | | | |
| Sempra Energy | SRE | | Yes | Annualized DPS | 4.10 | 4.35 | 2.27 | 3.57 | 3.05 | -2.6% | 4.58% | 8.5% | 42.6% | 0.00 | (72.55) |
| | | | | Annualized EPS | 3.66 | 4.23 | 4.62 | 4.17 | 6.00 | 6.3% | 4.58% | | | | |
| Southern Company | SO | Yes | | Annualized DPS | 2.54 | 2.62 | 2.70 | 2.62 | 3.10 | 2.8% | 4.58% | 9.0% | 40.1% | 0.00 | (69.80) |
| | | | | Annualized EPS | 3.25 | 3.42 | 3.61 | 3.43 | 5.15 | 7.0% | 4.58% | | | | |
| Wisconsin Energy Corporation | WEC | | Yes | Annualized DPS | 2.53 | 2.71 | 2.91 | 2.72 | 3.80 | 5.8% | 4.58% | 9.0% | 35.4% | 0.00 | (81.90) |
| | | | | Annualized EPS | 3.79 | 4.11 | 4.46 | 4.12 | 5.90 | 6.2% | 4.58% | | | | |
| Xcel Energy Inc. | XEL | Yes | | Annualized DPS | 1.70 | 1.80 | 1.92 | 1.81 | 2.66 | 6.7% | 4.58% | 8.8% | 36.8% | 0.00 | (60.72) |
| | | | | Annualized EPS | 2.78 | 2.96 | 3.17 | 2.97 | 4.25 | 6.2% | 4.58% | | | | |
| Company Proxy Group - Mean | | 16 | | | | | | | | | | 9.24% | 33.69% | 0.00 | |
| Staff Proxy Group - Mean | | | 16 | | | | | | | | | 9.43% | 32.28% | 0.00 | |

| [1] | [2] | [17] | [18] | [19] | [20] | [21] | [22] | [23] | [24] | [25] | [26] | [27] | [28] | [29] | [30] | [31] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
| Company | Ticker | Initial Stage | | | | | Transition Stage | | | | | | | | | |
| Alliant Energy Corporation | LNT | 1.81 | 1.92 | 2.04 | 2.16 | 2.29 | 2.42 | 2.64 | 2.85 | 3.02 | 3.16 | 3.30 | 3.46 | 3.61 | 3.78 | 3.95 |
| | | 2.85 | 2.85 | 3.14 | 3.45 | 3.80 | 4.15 | 4.55 | 4.91 | 5.21 | 5.45 | 5.70 | 5.96 | 6.24 | 6.52 | 6.82 |
| Ameren Corporation | AEE | 2.52 | 2.65 | 2.85 | 3.07 | 3.30 | 3.53 | 3.89 | 4.21 | 4.48 | 4.68 | 4.90 | 5.12 | 5.36 | 5.60 | 5.86 |
| | | 4.40 | 4.70 | 4.95 | 5.22 | 5.50 | 5.78 | 6.33 | 6.82 | 7.24 | 7.57 | 7.92 | 8.28 | 8.66 | 9.05 | 9.47 |
| American Electric Power Company, Inc. | AEP | 3.35 | 3.52 | 3.72 | 3.93 | 4.16 | 4.39 | 4.78 | 5.13 | 5.44 | 5.69 | 5.95 | 6.22 | 6.51 | 6.81 | 7.12 |
| | | 5.25 | 5.60 | 5.97 | 6.37 | 6.80 | 7.23 | 7.89 | 8.49 | 9.01 | 9.42 | 9.85 | 10.30 | 10.77 | 11.26 | 11.78 |
| Avista Corporation | AVA | 1.84 | 1.92 | 2.01 | 2.10 | 2.20 | 2.30 | 2.48 | 2.65 | 2.81 | 2.94 | 3.07 | 3.21 | 3.36 | 3.51 | 3.67 |
| | | 2.30 | 2.50 | 2.63 | 2.76 | 2.90 | 3.04 | 3.32 | 3.58 | 3.80 | 3.97 | 4.15 | 4.34 | 4.54 | 4.75 | 4.97 |
| Black Hills Corporation | BKH | 2.53 | 2.65 | 2.76 | 2.88 | 3.01 | 3.14 | 3.39 | 3.63 | 3.84 | 4.01 | 4.20 | 4.39 | 4.59 | 4.80 | 5.02 |
| | | 3.75 | 3.90 | 4.09 | 4.29 | 4.50 | 4.71 | 5.03 | 5.33 | 5.61 | 5.87 | 6.14 | 6.42 | 6.71 | 7.02 | 7.34 |
| CMS Energy Corporation | CMS | 1.95 | 2.04 | 2.12 | 2.21 | 2.30 | 2.39 | 2.59 | 2.77 | 2.93 | 3.07 | 3.21 | 3.35 | 3.51 | 3.67 | 3.84 |
| | | 3.05 | 3.30 | 3.44 | 3.59 | 3.75 | 3.91 | 4.26 | 4.58 | 4.86 | 5.08 | 5.31 | 5.55 | 5.81 | 6.07 | 6.35 |
| Consolidated Edison, Inc. | ED | 3.24 | 3.34 | 3.51 | 3.68 | 3.86 | 4.04 | 4.34 | 4.62 | 4.88 | 5.10 | 5.34 | 5.58 | 5.84 | 6.10 | 6.38 |
| | | 4.90 | 5.20 | 5.50 | 5.82 | 6.15 | 6.48 | 7.08 | 7.62 | 8.08 | 8.45 | 8.84 | 9.24 | 9.66 | 10.11 | 10.57 |
| Duke Energy Corporation | DUK | 4.06 | 4.14 | 4.19 | 4.25 | 4.30 | 4.35 | 4.61 | 4.86 | 5.10 | 5.34 | 5.58 | 5.84 | 6.10 | 6.38 | 6.67 |
| | | 5.60 | 6.00 | 6.32 | 6.65 | 7.00 | 7.35 | 7.97 | 8.54 | 9.04 | 9.46 | 9.89 | 10.34 | 10.82 | 11.31 | 11.83 |
| Entergy Corporation | ETR | 4.34 | 4.56 | 4.70 | 4.85 | 5.00 | 5.15 | 5.56 | 5.93 | 6.27 | 6.56 | 6.86 | 7.17 | 7.50 | 7.84 | 8.20 |
| | | 7.25 | 6.45 | 6.78 | 7.13 | 7.50 | 7.87 | 8.39 | 8.90 | 9.37 | 9.80 | 10.24 | 10.71 | 11.20 | 11.72 | 12.25 |
| Evergy, Inc. | EVRG | 2.48 | 2.61 | 2.75 | 2.90 | 3.05 | 3.20 | 3.49 | 3.76 | 3.98 | 4.17 | 4.36 | 4.56 | 4.76 | 4.98 | 5.21 |
| | | 3.60 | 3.85 | 4.16 | 4.49 | 4.85 | 5.21 | 5.72 | 6.18 | 6.57 | 6.88 | 7.19 | 7.52 | 7.86 | 8.22 | 8.60 |
| Fortis, Inc. | FTS | 2.29 | 2.53 | 2.62 | 2.71 | 2.80 | 2.89 | 3.15 | 3.38 | 3.58 | 3.74 | 3.91 | 4.09 | 4.28 | 4.47 | 4.68 |
| | | 2.90 | 2.95 | 3.20 | 3.46 | 3.75 | 4.04 | 4.41 | 4.74 | 5.03 | 5.26 | 5.50 | 5.75 | 6.02 | 6.29 | 6.58 |
| IDACORP, Inc. | IDA | 3.20 | 3.40 | 3.63 | 3.88 | 4.15 | 4.42 | 4.83 | 5.21 | 5.53 | 5.79 | 6.05 | 6.33 | 6.62 | 6.92 | 7.24 |
| | | 5.15 | 5.40 | 5.62 | 5.86 | 6.10 | 6.34 | 6.82 | 7.27 | 7.67 | 8.02 | 8.39 | 8.77 | 9.17 | 9.59 | 10.03 |
| NextEra Energy, Inc. | NEE | 1.87 | 2.06 | 2.12 | 2.19 | 2.26 | 2.33 | 2.55 | 2.76 | 2.93 | 3.06 | 3.20 | 3.35 | 3.50 | 3.66 | 3.83 |
| | | 3.20 | 3.40 | 3.71 | 4.04 | 4.40 | 4.76 | 5.32 | 5.82 | 6.22 | 6.50 | 6.80 | 7.11 | 7.44 | 7.78 | 8.14 |
| NorthWestern Corporation | NWE | 2.56 | 2.60 | 2.65 | 2.71 | 2.76 | 2.81 | 2.98 | 3.15 | 3.31 | 3.46 | 3.62 | 3.79 | 3.96 | 4.14 | 4.33 |
| | | 3.45 | 3.60 | 3.77 | 3.96 | 4.15 | 4.34 | 4.67 | 4.97 | 5.24 | 5.48 | 5.74 | 6.00 | 6.27 | 6.56 | 6.86 |
| OGE Energy Corporation | OGE | 1.66 | 1.78 | 1.80 | 1.83 | 1.85 | 1.87 | 1.99 | 2.11 | 2.22 | 2.32 | 2.43 | 2.54 | 2.65 | 2.78 | 2.90 |
| | | 2.05 | 2.15 | 2.44 | 2.77 | 3.15 | 3.53 | 3.85 | 4.15 | 4.40 | 4.60 | 4.81 | 5.03 | 5.26 | 5.50 | 5.75 |
| Pinnacle West Capital Corporation | PNW | 3.48 | 3.54 | 3.61 | 3.68 | 3.75 | 3.82 | 4.06 | 4.29 | 4.51 | 4.72 | 4.93 | 5.16 | 5.39 | 5.64 | 5.90 |
| | | 4.20 | 4.50 | 4.87 | 5.27 | 5.70 | 6.13 | 6.54 | 6.93 | 7.29 | 7.63 | 7.98 | 8.34 | 8.72 | 9.12 | 9.54 |
| Portland General Electric Company | POR | 1.88 | 1.98 | 2.10 | 2.23 | 2.36 | 2.49 | 2.72 | 2.93 | 3.11 | 3.25 | 3.40 | 3.56 | 3.72 | 3.89 | 4.07 |
| | | 2.70 | 3.00 | 3.20 | 3.42 | 3.65 | 3.88 | 4.21 | 4.51 | 4.77 | 4.99 | 5.22 | 5.46 | 5.71 | 5.97 | 6.24 |
| PPL Corporation | PPL | 0.95 | 1.03 | 1.10 | 1.18 | 1.26 | 1.34 | 1.38 | 1.42 | 1.48 | 1.55 | 1.62 | 1.69 | 1.77 | 1.85 | 1.93 |
| | | 1.55 | 1.70 | 1.82 | 1.96 | 2.10 | 2.24 | 2.48 | 2.70 | 2.88 | 3.01 | 3.15 | 3.29 | 3.44 | 3.60 | 3.77 |
| Public Service Enterprise Group Inc. | PEG | 2.28 | 2.40 | 2.53 | 2.67 | 2.82 | 2.97 | 3.23 | 3.47 | 3.67 | 3.84 | 4.02 | 4.20 | 4.39 | 4.60 | 4.81 |
| | | 3.50 | 3.70 | 3.92 | 4.15 | 4.40 | 4.65 | 5.00 | 5.33 | 5.62 | 5.88 | 6.15 | 6.43 | 6.73 | 7.03 | 7.36 |
| Sempra Energy | SRE | 2.38 | 2.50 | 2.67 | 2.85 | 3.05 | 3.25 | 3.33 | 3.43 | 3.57 | 3.73 | 3.90 | 4.08 | 4.27 | 4.46 | 4.67 |
| | | 4.50 | 4.80 | 5.17 | 5.57 | 6.00 | 6.43 | 7.04 | 7.59 | 8.05 | 8.42 | 8.81 | 9.21 | 9.63 | 10.07 | 10.54 |
| Southern Company | SO | 2.78 | 2.86 | 2.94 | 3.02 | 3.10 | 3.18 | 3.40 | 3.60 | 3.80 | 3.97 | 4.15 | 4.34 | 4.54 | 4.75 | 4.96 |
| | | 3.60 | 4.00 | 4.35 | 4.73 | 5.15 | 5.57 | 6.12 | 6.63 | 7.05 | 7.37 | 7.71 | 8.06 | 8.43 | 8.82 | 9.22 |
| Wisconsin Energy Corporation | WEC | 3.12 | 3.33 | 3.48 | 3.64 | 3.80 | 3.96 | 4.32 | 4.65 | 4.93 | 5.16 | 5.39 | 5.64 | 5.90 | 6.17 | 6.45 |
| | | 4.60 | 4.90 | 5.21 | 5.55 | 5.90 | 6.25 | 6.84 | 7.37 | 7.82 | 8.18 | 8.56 | 8.95 | 9.36 | 9.79 | 10.23 |
| Xcel Energy Inc. | XEL | 2.08 | 2.22 | 2.36 | 2.50 | 2.66 | 2.82 | 3.09 | 3.34 | 3.55 | 3.71 | 3.88 | 4.06 | 4.24 | 4.44 | 4.64 |
| | | 3.35 | 3.55 | 3.77 | 4.00 | 4.25 | 4.50 | 4.92 | 5.30 | 5.63 | 5.88 | 6.15 | 6.43 | 6.73 | 7.04 | 7.36 |
| Company Proxy Group - Mean | | | | | | | | | | | | | | | | |
| Staff Proxy Group - Mean | | | | | | | | | | | | | | | | |

**E.O.Y. Cash Flows**

| [1] | [2] | [32] | [33] | [34] | [35] | [36] | [37] | [38] | [39] | [40] | [41] | [42] | [43] | [44] | [45] | [46] | [47] | [48] | [49] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 | 2048 | 2049 | 2050 | 2051 | 2052 | 2052 | 2052 | 2053 |
| | | Final Stage | | | | | | | | | | | | | | Terminal | | | |
| Company | Ticker | | | | | | | | | | | | | | | Value | | Sale | |
| Alliant Energy Corporation | LNT | 4.13 | 4.32 | 4.52 | 4.73 | 4.94 | 5.17 | 5.41 | 5.65 | 5.91 | 6.18 | 6.47 | 6.76 | 7.07 | 7.40 | 251.14 | 7.73 | 243.40 | |
| | | 7.13 | 7.46 | 7.80 | 8.16 | 8.53 | 8.92 | 9.33 | 9.76 | 10.20 | 10.67 | 11.16 | 11.67 | 12.20 | 12.76 | | 13.35 | | 13.96 |
| Ameren Corporation | AEE | 6.13 | 6.41 | 6.70 | 7.01 | 7.33 | 7.66 | 8.01 | 8.38 | 8.76 | 9.16 | 9.58 | 10.02 | 10.48 | 10.96 | 322.82 | 11.46 | 311.36 | |
| | | 9.90 | 10.36 | 10.83 | 11.33 | 11.84 | 12.39 | 12.95 | 13.55 | 14.17 | 14.81 | 15.49 | 16.20 | 16.94 | 17.72 | | 18.53 | | 19.38 |
| American Electric Power Company, Inc. | AEP | 7.44 | 7.78 | 8.14 | 8.51 | 8.90 | 9.31 | 9.74 | 10.18 | 10.65 | 11.13 | 11.64 | 12.18 | 12.73 | 13.32 | 377.73 | 13.93 | 363.81 | |
| | | 12.32 | 12.88 | 13.47 | 14.09 | 14.73 | 15.41 | 16.11 | 16.85 | 17.62 | 18.43 | 19.27 | 20.15 | 21.08 | 22.04 | | 23.05 | | 24.10 |
| Avista Corporation | AVA | 3.84 | 4.02 | 4.20 | 4.39 | 4.59 | 4.80 | 5.02 | 5.25 | 5.49 | 5.74 | 6.01 | 6.28 | 6.57 | 6.87 | 159.44 | 7.18 | 152.25 | |
| | | 5.20 | 5.43 | 5.68 | 5.94 | 6.21 | 6.50 | 6.80 | 7.11 | 7.43 | 7.77 | 8.13 | 8.50 | 8.89 | 9.30 | | 9.72 | | 10.17 |
| Black Hills Corporation | BKH | 5.25 | 5.49 | 5.74 | 6.01 | 6.28 | 6.57 | 6.87 | 7.18 | 7.51 | 7.86 | 8.22 | 8.59 | 8.99 | 9.40 | 218.81 | 9.83 | 208.98 | |
| | | 7.67 | 8.03 | 8.39 | 8.78 | 9.18 | 9.60 | 10.04 | 10.50 | 10.98 | 11.48 | 12.01 | 12.56 | 13.13 | 13.73 | | 14.36 | | 15.02 |
| CMS Energy Corporation | CMS | 4.01 | 4.19 | 4.39 | 4.59 | 4.80 | 5.02 | 5.25 | 5.49 | 5.74 | 6.00 | 6.28 | 6.56 | 6.86 | 7.18 | 252.63 | 7.51 | 245.12 | |
| | | 6.64 | 6.95 | 7.26 | 7.60 | 7.94 | 8.31 | 8.69 | 9.09 | 9.50 | 9.94 | 10.39 | 10.87 | 11.37 | 11.89 | | 12.43 | | 13.00 |
| Consolidated Edison, Inc. | ED | 6.68 | 6.98 | 7.30 | 7.64 | 7.98 | 8.35 | 8.73 | 9.13 | 9.55 | 9.99 | 10.44 | 10.92 | 11.42 | 11.94 | 413.83 | 12.49 | 401.34 | |
| | | 11.05 | 11.56 | 12.09 | 12.64 | 13.22 | 13.82 | 14.46 | 15.12 | 15.81 | 16.53 | 17.29 | 18.08 | 18.91 | 19.77 | | 20.68 | | 21.63 |
| Duke Energy Corporation | DUK | 6.98 | 7.30 | 7.63 | 7.98 | 8.35 | 8.73 | 9.13 | 9.55 | 9.98 | 10.44 | 10.92 | 11.42 | 11.94 | 12.49 | 430.99 | 13.06 | 417.92 | |
| | | 12.37 | 12.94 | 13.53 | 14.15 | 14.80 | 15.47 | 16.18 | 16.92 | 17.70 | 18.51 | 19.35 | 20.24 | 21.17 | 22.13 | | 23.15 | | 24.21 |
| Entergy Corporation | ETR | 8.58 | 8.97 | 9.38 | 9.81 | 10.26 | 10.73 | 11.22 | 11.73 | 12.27 | 12.83 | 13.42 | 14.03 | 14.67 | 15.34 | 363.72 | 16.05 | 347.68 | |
| | | 12.81 | 13.40 | 14.01 | 14.65 | 15.33 | 16.03 | 16.76 | 17.53 | 18.33 | 19.17 | 20.05 | 20.96 | 21.92 | 22.93 | | 23.98 | | 25.07 |
| Evergy, Inc. | EVRG | 5.45 | 5.70 | 5.96 | 6.23 | 6.52 | 6.81 | 7.13 | 7.45 | 7.79 | 8.15 | 8.52 | 8.91 | 9.32 | 9.75 | 260.29 | 10.19 | 250.10 | |
| | | 8.99 | 9.41 | 9.84 | 10.29 | 10.76 | 11.25 | 11.76 | 12.30 | 12.87 | 13.45 | 14.07 | 14.71 | 15.39 | 16.09 | | 16.83 | | 17.60 |
| Fortis, Inc. | FTS | 4.89 | 5.12 | 5.35 | 5.59 | 5.85 | 6.12 | 6.40 | 6.69 | 7.00 | 7.32 | 7.65 | 8.00 | 8.37 | 8.75 | 194.65 | 9.15 | 185.50 | |
| | | 6.88 | 7.20 | 7.53 | 7.87 | 8.23 | 8.61 | 9.00 | 9.41 | 9.84 | 10.30 | 10.77 | 11.26 | 11.77 | 12.31 | | 12.88 | | 13.47 |
| IDACORP, Inc. | IDA | 7.57 | 7.92 | 8.28 | 8.66 | 9.05 | 9.47 | 9.90 | 10.36 | 10.83 | 11.33 | 11.84 | 12.39 | 12.95 | 13.55 | 393.02 | 14.17 | 378.86 | |
| | | 10.49 | 10.97 | 11.47 | 12.00 | 12.55 | 13.12 | 13.72 | 14.35 | 15.01 | 15.69 | 16.41 | 17.16 | 17.95 | 18.77 | | 19.63 | | 20.53 |
| NextEra Energy, Inc. | NEE | 4.01 | 4.19 | 4.38 | 4.58 | 4.79 | 5.01 | 5.24 | 5.48 | 5.73 | 5.99 | 6.27 | 6.55 | 6.85 | 7.17 | 310.24 | 7.49 | 302.75 | |
| | | 8.51 | 8.90 | 9.31 | 9.73 | 10.18 | 10.64 | 11.13 | 11.64 | 12.17 | 12.73 | 13.31 | 13.92 | 14.56 | 15.22 | | 15.92 | | 16.65 |
| NorthWestern Corporation | NWE | 4.53 | 4.74 | 4.95 | 5.18 | 5.42 | 5.66 | 5.92 | 6.19 | 6.48 | 6.77 | 7.08 | 7.41 | 7.75 | 8.10 | 208.05 | 8.47 | 199.58 | |
| | | 7.17 | 7.50 | 7.85 | 8.20 | 8.58 | 8.97 | 9.38 | 9.81 | 10.26 | 10.73 | 11.22 | 11.74 | 12.27 | 12.84 | | 13.42 | | 14.04 |
| OGE Energy Corporation | OGE | 3.04 | 3.17 | 3.32 | 3.47 | 3.63 | 3.80 | 3.97 | 4.15 | 4.34 | 4.54 | 4.75 | 4.97 | 5.19 | 5.43 | 199.88 | 5.68 | 194.20 | |
| | | 6.02 | 6.29 | 6.58 | 6.88 | 7.20 | 7.53 | 7.87 | 8.23 | 8.61 | 9.00 | 9.41 | 9.84 | 10.29 | 10.77 | | 11.26 | | 11.77 |
| Pinnacle West Capital Corporation | PNW | 6.17 | 6.45 | 6.75 | 7.06 | 7.38 | 7.72 | 8.07 | 8.44 | 8.83 | 9.23 | 9.65 | 10.09 | 10.56 | 11.04 | 341.75 | 11.54 | 330.21 | |
| | | 9.98 | 10.43 | 10.91 | 11.41 | 11.93 | 12.48 | 13.05 | 13.65 | 14.27 | 14.92 | 15.61 | 16.32 | 17.07 | 17.85 | | 18.67 | | 19.52 |
| Portland General Electric Company | POR | 4.26 | 4.45 | 4.65 | 4.87 | 5.09 | 5.32 | 5.57 | 5.82 | 6.09 | 6.37 | 6.66 | 6.96 | 7.28 | 7.61 | 204.02 | 7.96 | 196.06 | |
| | | 6.52 | 6.82 | 7.14 | 7.46 | 7.80 | 8.16 | 8.53 | 8.93 | 9.33 | 9.76 | 10.21 | 10.68 | 11.16 | 11.67 | | 12.21 | | 12.77 |
| PPL Corporation | PPL | 2.02 | 2.12 | 2.21 | 2.31 | 2.42 | 2.53 | 2.65 | 2.77 | 2.89 | 3.03 | 3.17 | 3.31 | 3.46 | 3.62 | 135.82 | 3.79 | 132.03 | |
| | | 3.94 | 4.12 | 4.31 | 4.50 | 4.71 | 4.93 | 5.15 | 5.39 | 5.63 | 5.89 | 6.16 | 6.44 | 6.74 | 7.05 | | 7.37 | | 7.71 |
| Public Service Enterprise Group Inc. | PEG | 5.03 | 5.26 | 5.50 | 5.75 | 6.01 | 6.29 | 6.57 | 6.87 | 7.19 | 7.52 | 7.86 | 8.22 | 8.60 | 8.99 | 263.52 | 9.40 | 254.12 | |
| | | 7.69 | 8.04 | 8.41 | 8.80 | 9.20 | 9.62 | 10.06 | 10.52 | 11.00 | 11.51 | 12.03 | 12.59 | 13.16 | 13.76 | | 14.39 | | 15.05 |
| Sempra Energy | SRE | 4.88 | 5.10 | 5.34 | 5.58 | 5.84 | 6.10 | 6.38 | 6.68 | 6.98 | 7.30 | 7.64 | 7.99 | 8.35 | 8.73 | 356.71 | 9.13 | 347.58 | |
| | | 11.02 | 11.52 | 12.05 | 12.60 | 13.18 | 13.78 | 14.41 | 15.07 | 15.76 | 16.48 | 17.24 | 18.03 | 18.85 | 19.71 | | 20.62 | | 21.56 |
| Southern Company | SO | 5.19 | 5.43 | 5.68 | 5.94 | 6.21 | 6.49 | 6.79 | 7.10 | 7.43 | 7.77 | 8.12 | 8.49 | 8.88 | 9.29 | 375.51 | 9.72 | 365.80 | |
| | | 9.64 | 10.08 | 10.54 | 11.03 | 11.53 | 12.06 | 12.61 | 13.19 | 13.79 | 14.42 | 15.08 | 15.77 | 16.50 | 17.25 | | 18.04 | | 18.87 |
| Wisconsin Energy Corporation | WEC | 6.74 | 7.05 | 7.38 | 7.71 | 8.07 | 8.43 | 8.82 | 9.22 | 9.65 | 10.09 | 10.55 | 11.03 | 11.54 | 12.07 | 385.50 | 12.62 | 372.88 | |
| | | 10.70 | 11.19 | 11.71 | 12.24 | 12.80 | 13.39 | 14.00 | 14.64 | 15.31 | 16.01 | 16.74 | 17.51 | 18.31 | 19.15 | | 20.03 | | 20.94 |
| Xcel Energy Inc. | XEL | 4.85 | 5.07 | 5.31 | 5.55 | 5.80 | 6.07 | 6.35 | 6.64 | 6.94 | 7.26 | 7.59 | 7.94 | 8.30 | 8.68 | 282.02 | 9.08 | 272.94 | |
| | | 7.70 | 8.05 | 8.42 | 8.80 | 9.20 | 9.63 | 10.07 | 10.53 | 11.01 | 11.51 | 12.04 | 12.59 | 13.17 | 13.77 | | 14.40 | | 15.06 |

Company Proxy Group - Mean
Staff Proxy Group - Mean

**B.O.Y. Cash Flows**

| [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] | [13] | [14] | [15] | [16] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | Proxy Group | Staff Proxy Group | | 2020 | 2021 | 2022 | 2020-2022 | 2026-2028 | (2020-22 - 2026-28) | GDP Growth Rate | IRR | Terminal Value as % of $NPV_{DIV}$ | NPV @ IRR | Recent Price* |
| Alliant Energy Corporation | LNT | Yes | Yes | Annualized DPS | 1.52 | 1.61 | 1.71 | 1.61 | 2.29 | 6.0% | 4.58% | 9.4% | 34.6% | 0.00 | (49.71) |
| | | | | Annualized EPS | 2.46 | 2.62 | 2.73 | 2.60 | 3.80 | 6.5% | 4.58% | | | | |
| Ameren Corporation | AEE | Yes | Yes | Annualized DPS | 2.00 | 2.20 | 2.36 | 2.19 | 3.30 | 7.1% | 4.58% | 9.3% | 32.0% | 0.00 | (70.70) |
| | | | | Annualized EPS | 3.50 | 3.84 | 4.14 | 3.83 | 5.50 | 6.2% | 4.58% | | | | |
| American Electric Power Company, Inc. | AEP | Yes | | Annualized DPS | 2.84 | 3.00 | 3.17 | 3.00 | 4.16 | 5.6% | 4.58% | 9.8% | 29.2% | 0.00 | (79.24) |
| | | | | Annualized EPS | 4.42 | 4.96 | 5.09 | 4.82 | 6.80 | 5.9% | 4.58% | | | | |
| Avista Corporation | AVA | Yes | Yes | Annualized DPS | 1.62 | 1.69 | 1.76 | 1.69 | 2.20 | 4.5% | 4.58% | 10.6% | 22.4% | 0.00 | (34.45) |
| | | | | Annualized EPS | 1.90 | 2.09 | 2.12 | 2.04 | 2.90 | 6.1% | 4.58% | | | | |
| Black Hills Corporation | BKH | | Yes | Annualized DPS | 2.17 | 2.29 | 2.41 | 2.29 | 3.01 | 4.7% | 4.58% | 9.9% | 24.6% | 0.00 | (52.19) |
| | | | | Annualized EPS | 3.73 | 3.75 | 3.99 | 3.82 | 4.50 | 2.8% | 4.58% | | | | |
| CMS Energy Corporation | CMS | Yes | | Annualized DPS | 1.63 | 1.74 | 1.84 | 1.74 | 2.30 | 4.8% | 4.58% | 8.5% | 38.4% | 0.00 | (57.52) |
| | | | | Annualized EPS | 2.64 | 2.58 | 2.84 | 2.69 | 3.75 | 5.7% | 4.58% | | | | |
| Consolidated Edison, Inc. | ED | | Yes | Annualized DPS | 3.06 | 3.10 | 3.16 | 3.11 | 3.86 | 3.7% | 4.58% | 8.7% | 37.1% | 0.00 | (90.94) |
| | | | | Annualized EPS | 4.17 | 4.38 | 4.55 | 4.37 | 6.15 | 5.9% | 4.58% | | | | |
| Duke Energy Corporation | DUK | Yes | | Annualized DPS | 3.82 | 3.90 | 3.98 | 3.90 | 4.30 | 1.6% | 4.58% | 8.7% | 36.4% | 0.00 | (96.68) |
| | | | | Annualized EPS | 5.12 | 5.23 | 5.33 | 5.23 | 7.00 | 5.0% | 4.58% | | | | |
| Entergy Corporation | ETR | Yes | | Annualized DPS | 3.74 | 3.86 | 4.10 | 3.90 | 5.00 | 4.2% | 4.58% | 8.9% | 28.0% | 0.00 | (100.53) |
| | | | | Annualized EPS | 6.90 | 6.87 | 5.39 | 6.39 | 7.50 | 2.7% | 4.58% | | | | |
| Evergy, Inc. | EVRG | Yes | Yes | Annualized DPS | 2.05 | 2.18 | 2.33 | 2.19 | 3.05 | 5.7% | 4.58% | 10.5% | 25.6% | 0.00 | (51.16) |
| | | | | Annualized EPS | 2.72 | 3.83 | 3.26 | 3.27 | 4.85 | 6.8% | 4.58% | | | | |
| Fortis, Inc. | FTS | | Yes | Annualized DPS | 1.94 | 2.05 | 2.17 | 2.05 | 2.80 | 5.3% | 4.58% | 11.3% | 19.9% | 0.00 | (39.95) |
| | | | | Annualized EPS | 2.60 | 2.61 | 2.78 | 2.66 | 3.75 | 5.9% | 4.58% | | | | |
| IDACORP, Inc. | IDA | Yes | Yes | Annualized DPS | 2.72 | 2.88 | 3.04 | 2.88 | 4.15 | 6.3% | 4.58% | 8.8% | 33.3% | 0.00 | (95.05) |
| | | | | Annualized EPS | 4.69 | 4.85 | 5.11 | 4.88 | 6.10 | 3.8% | 4.58% | | | | |
| NextEra Energy, Inc. | NEE | Yes | | Annualized DPS | 1.40 | 1.54 | 1.70 | 1.55 | 2.26 | 6.5% | 4.58% | 8.8% | 42.0% | 0.00 | (58.19) |
| | | | | Annualized EPS | 2.31 | 2.54 | 2.91 | 2.59 | 4.40 | 9.3% | 4.58% | | | | |
| NorthWestern Corporation | NWE | Yes | Yes | Annualized DPS | 2.40 | 2.48 | 2.52 | 2.47 | 2.76 | 1.9% | 4.58% | 9.6% | 26.8% | 0.00 | (49.05) |
| | | | | Annualized EPS | 3.22 | 3.50 | 3.29 | 3.34 | 4.15 | 3.7% | 4.58% | | | | |
| OGE Energy Corporation | OGE | Yes | Yes | Annualized DPS | 1.57 | 1.62 | 1.64 | 1.61 | 1.85 | 2.4% | 4.58% | 10.2% | 32.5% | 0.00 | (33.81) |
| | | | | Annualized EPS | 2.08 | 2.35 | 2.25 | 2.23 | 3.15 | 6.0% | 4.58% | | | | |
| Pinnacle West Capital Corporation | PNW | Yes | Yes | Annualized DPS | 3.18 | 3.34 | 3.40 | 3.31 | 3.75 | 2.1% | 4.58% | 9.6% | 30.9% | 0.00 | (71.04) |
| | | | | Annualized EPS | 4.88 | 5.47 | 4.27 | 4.87 | 5.70 | 2.6% | 4.58% | | | | |
| Portland General Electric Company | POR | Yes | Yes | Annualized DPS | 1.56 | 1.68 | 1.77 | 1.67 | 2.36 | 6.0% | 4.58% | 10.2% | 26.6% | 0.00 | (41.46) |
| | | | | Annualized EPS | 2.75 | 2.72 | 2.74 | 2.74 | 3.65 | 4.9% | 4.58% | | | | |
| PPL Corporation | PPL | | Yes | Annualized DPS | 1.66 | 1.66 | 1.07 | 1.46 | 1.26 | -2.4% | 4.58% | 9.2% | 36.8% | 0.00 | (26.56) |
| | | | | Annualized EPS | 2.05 | 0.52 | 1.40 | 1.32 | 2.10 | 8.0% | 4.58% | | | | |
| Public Service Enterprise Group Inc. | PEG | | Yes | Annualized DPS | 1.96 | 2.04 | 2.16 | 2.05 | 2.82 | 5.4% | 4.58% | 9.2% | 31.7% | 0.00 | (59.09) |
| | | | | Annualized EPS | 3.43 | 3.63 | 3.47 | 3.51 | 4.40 | 3.8% | 4.58% | | | | |
| Sempra Energy | SRE | | Yes | Annualized DPS | 4.10 | 4.35 | 2.27 | 3.57 | 3.05 | -2.6% | 4.58% | 8.7% | 40.8% | 0.00 | (72.55) |
| | | | | Annualized EPS | 3.66 | 4.23 | 4.62 | 4.17 | 6.00 | 6.3% | 4.58% | | | | |
| Southern Company | SO | Yes | | Annualized DPS | 2.54 | 2.62 | 2.70 | 2.62 | 3.10 | 2.8% | 4.58% | 9.2% | 38.6% | 0.00 | (69.80) |
| | | | | Annualized EPS | 3.25 | 3.42 | 3.61 | 3.43 | 5.15 | 7.0% | 4.58% | | | | |
| Wisconsin Energy Corporation | WEC | | Yes | Annualized DPS | 2.53 | 2.71 | 2.91 | 2.72 | 3.80 | 5.8% | 4.58% | 9.2% | 33.6% | 0.00 | (81.90) |
| | | | | Annualized EPS | 3.79 | 4.11 | 4.46 | 4.12 | 5.90 | 6.2% | 4.58% | | | | |
| Xcel Energy Inc. | XEL | Yes | | Annualized DPS | 1.70 | 1.80 | 1.92 | 1.81 | 2.66 | 6.7% | 4.58% | 9.0% | 34.9% | 0.00 | (60.72) |
| | | | | Annualized EPS | 2.78 | 2.96 | 3.17 | 2.97 | 4.25 | 6.2% | 4.58% | | | | |
| Company Proxy Group - Mean | | 16 | | | | | | | | | | 9.44% | 32.00% | 0.00 | |
| Staff Proxy Group - Mean | | | 16 | | | | | | | | | 9.64% | 30.57% | 0.00 | |

**B.O.Y. Cash Flows**

| [1] | [2] | [17] | [18] | [19] | [20] | [21] | [22] | [23] | [24] | [25] | [26] | [27] | [28] | [29] | [30] | [31] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
| | | Initial Stage | | | | | Transition Stage | | | | | | | | | |
| Company | Ticker | | | | | | | | | | | | | | | |
| Alliant Energy Corporation | LNT | 1.92 | 2.04 | 2.16 | 2.29 | 2.42 | 2.64 | 2.85 | 3.02 | 3.16 | 3.30 | 3.46 | 3.61 | 3.78 | 3.95 | 4.13 |
| | | 2.85 | 2.85 | 3.14 | 3.45 | 3.80 | 4.15 | 4.55 | 4.91 | 5.21 | 5.45 | 5.70 | 5.96 | 6.24 | 6.52 | 6.82 |
| Ameren Corporation | AEE | 2.65 | 2.85 | 3.07 | 3.30 | 3.53 | 3.89 | 4.21 | 4.48 | 4.68 | 4.90 | 5.12 | 5.36 | 5.60 | 5.86 | 6.13 |
| | | 4.40 | 4.70 | 4.95 | 5.22 | 5.50 | 5.78 | 6.33 | 6.82 | 7.24 | 7.57 | 7.92 | 8.28 | 8.66 | 9.05 | 9.47 |
| American Electric Power Company, Inc. | AEP | 3.52 | 3.72 | 3.93 | 4.16 | 4.39 | 4.78 | 5.13 | 5.44 | 5.69 | 5.95 | 6.22 | 6.51 | 6.81 | 7.12 | 7.44 |
| | | 5.25 | 5.60 | 5.97 | 6.37 | 6.80 | 7.23 | 7.89 | 8.49 | 9.01 | 9.42 | 9.85 | 10.30 | 10.77 | 11.26 | 11.78 |
| Avista Corporation | AVA | 1.92 | 2.01 | 2.10 | 2.20 | 2.30 | 2.48 | 2.65 | 2.81 | 2.94 | 3.07 | 3.21 | 3.36 | 3.51 | 3.67 | 3.84 |
| | | 2.30 | 2.50 | 2.63 | 2.76 | 2.90 | 3.04 | 3.32 | 3.58 | 3.80 | 3.97 | 4.15 | 4.34 | 4.54 | 4.75 | 4.97 |
| Black Hills Corporation | BKH | 2.65 | 2.76 | 2.88 | 3.01 | 3.14 | 3.39 | 3.63 | 3.84 | 4.01 | 4.20 | 4.39 | 4.59 | 4.80 | 5.02 | 5.25 |
| | | 3.75 | 3.90 | 4.09 | 4.29 | 4.50 | 4.71 | 5.03 | 5.33 | 5.61 | 5.87 | 6.14 | 6.42 | 6.71 | 7.02 | 7.34 |
| CMS Energy Corporation | CMS | 2.04 | 2.12 | 2.21 | 2.30 | 2.39 | 2.59 | 2.77 | 2.93 | 3.07 | 3.21 | 3.35 | 3.51 | 3.67 | 3.84 | 4.01 |
| | | 3.05 | 3.30 | 3.44 | 3.59 | 3.75 | 3.91 | 4.26 | 4.58 | 4.86 | 5.08 | 5.31 | 5.55 | 5.81 | 6.07 | 6.35 |
| Consolidated Edison, Inc. | ED | 3.34 | 3.51 | 3.68 | 3.86 | 4.04 | 4.34 | 4.62 | 4.88 | 5.10 | 5.34 | 5.58 | 5.84 | 6.10 | 6.38 | 6.68 |
| | | 4.90 | 5.20 | 5.50 | 5.82 | 6.15 | 6.48 | 7.08 | 7.62 | 8.08 | 8.45 | 8.84 | 9.24 | 9.66 | 10.11 | 10.57 |
| Duke Energy Corporation | DUK | 4.14 | 4.19 | 4.25 | 4.30 | 4.35 | 4.61 | 4.86 | 5.10 | 5.34 | 5.58 | 5.84 | 6.10 | 6.38 | 6.67 | 6.98 |
| | | 5.60 | 6.00 | 6.32 | 6.65 | 7.00 | 7.35 | 7.97 | 8.54 | 9.04 | 9.46 | 9.89 | 10.34 | 10.82 | 11.31 | 11.83 |
| Entergy Corporation | ETR | 4.56 | 4.70 | 4.85 | 5.00 | 5.15 | 5.56 | 5.93 | 6.27 | 6.56 | 6.86 | 7.17 | 7.50 | 7.84 | 8.20 | 8.58 |
| | | 7.25 | 6.45 | 6.78 | 7.13 | 7.50 | 7.87 | 8.39 | 8.90 | 9.37 | 9.80 | 10.24 | 10.71 | 11.20 | 11.72 | 12.25 |
| Evergy, Inc. | EVRG | 2.61 | 2.75 | 2.90 | 3.05 | 3.20 | 3.49 | 3.76 | 3.98 | 4.17 | 4.36 | 4.56 | 4.76 | 4.98 | 5.21 | 5.45 |
| | | 3.60 | 3.85 | 4.16 | 4.49 | 4.85 | 5.21 | 5.72 | 6.18 | 6.57 | 6.88 | 7.19 | 7.52 | 7.86 | 8.22 | 8.60 |
| Fortis, Inc. | FTS | 2.53 | 2.62 | 2.71 | 2.80 | 2.89 | 3.15 | 3.38 | 3.58 | 3.74 | 3.91 | 4.09 | 4.28 | 4.47 | 4.68 | 4.89 |
| | | 2.90 | 2.95 | 3.20 | 3.46 | 3.75 | 4.04 | 4.41 | 4.74 | 5.03 | 5.26 | 5.50 | 5.75 | 6.02 | 6.29 | 6.58 |
| IDACORP, Inc. | IDA | 3.40 | 3.63 | 3.88 | 4.15 | 4.42 | 4.83 | 5.21 | 5.53 | 5.79 | 6.05 | 6.33 | 6.62 | 6.92 | 7.24 | 7.57 |
| | | 5.15 | 5.40 | 5.62 | 5.86 | 6.10 | 6.34 | 6.82 | 7.27 | 7.67 | 8.02 | 8.39 | 8.77 | 9.17 | 9.59 | 10.03 |
| NextEra Energy, Inc. | NEE | 2.06 | 2.12 | 2.19 | 2.26 | 2.33 | 2.55 | 2.76 | 2.93 | 3.06 | 3.20 | 3.35 | 3.50 | 3.66 | 3.83 | 4.01 |
| | | 3.20 | 3.40 | 3.71 | 4.04 | 4.40 | 4.76 | 5.32 | 5.82 | 6.22 | 6.50 | 6.80 | 7.11 | 7.44 | 7.78 | 8.14 |
| NorthWestern Corporation | NWE | 2.60 | 2.65 | 2.71 | 2.76 | 2.81 | 2.98 | 3.15 | 3.31 | 3.46 | 3.62 | 3.79 | 3.96 | 4.14 | 4.33 | 4.53 |
| | | 3.45 | 3.60 | 3.77 | 3.96 | 4.15 | 4.34 | 4.67 | 4.97 | 5.24 | 5.48 | 5.74 | 6.00 | 6.27 | 6.56 | 6.86 |
| OGE Energy Corporation | OGE | 1.78 | 1.80 | 1.83 | 1.85 | 1.87 | 1.99 | 2.11 | 2.22 | 2.32 | 2.43 | 2.54 | 2.65 | 2.78 | 2.90 | 3.04 |
| | | 2.05 | 2.15 | 2.44 | 2.77 | 3.15 | 3.53 | 3.85 | 4.15 | 4.40 | 4.60 | 4.81 | 5.03 | 5.26 | 5.50 | 5.75 |
| Pinnacle West Capital Corporation | PNW | 3.54 | 3.61 | 3.68 | 3.75 | 3.82 | 4.06 | 4.29 | 4.51 | 4.72 | 4.93 | 5.16 | 5.39 | 5.64 | 5.90 | 6.17 |
| | | 4.20 | 4.50 | 4.87 | 5.27 | 5.70 | 6.13 | 6.54 | 6.93 | 7.29 | 7.63 | 7.98 | 8.34 | 8.72 | 9.12 | 9.54 |
| Portland General Electric Company | POR | 1.98 | 2.10 | 2.23 | 2.36 | 2.49 | 2.72 | 2.93 | 3.11 | 3.25 | 3.40 | 3.56 | 3.72 | 3.89 | 4.07 | 4.26 |
| | | 2.70 | 3.00 | 3.20 | 3.42 | 3.65 | 3.88 | 4.21 | 4.51 | 4.77 | 4.99 | 5.22 | 5.46 | 5.71 | 5.97 | 6.24 |
| PPL Corporation | PPL | 1.03 | 1.10 | 1.18 | 1.26 | 1.34 | 1.38 | 1.42 | 1.48 | 1.55 | 1.62 | 1.69 | 1.77 | 1.85 | 1.93 | 2.02 |
| | | 1.55 | 1.70 | 1.82 | 1.96 | 2.10 | 2.24 | 2.48 | 2.70 | 2.88 | 3.01 | 3.15 | 3.29 | 3.44 | 3.60 | 3.77 |
| Public Service Enterprise Group Inc. | PEG | 2.40 | 2.53 | 2.67 | 2.82 | 2.97 | 3.23 | 3.47 | 3.67 | 3.84 | 4.02 | 4.20 | 4.39 | 4.60 | 4.81 | 5.03 |
| | | 3.50 | 3.70 | 3.92 | 4.15 | 4.40 | 4.65 | 5.00 | 5.33 | 5.62 | 5.88 | 6.15 | 6.43 | 6.73 | 7.03 | 7.36 |
| Sempra Energy | SRE | 2.50 | 2.67 | 2.85 | 3.05 | 3.25 | 3.33 | 3.43 | 3.57 | 3.73 | 3.90 | 4.08 | 4.27 | 4.46 | 4.67 | 4.88 |
| | | 4.50 | 4.80 | 5.17 | 5.57 | 6.00 | 6.43 | 7.04 | 7.59 | 8.05 | 8.42 | 8.81 | 9.21 | 9.63 | 10.07 | 10.54 |
| Southern Company | SO | 2.86 | 2.94 | 3.02 | 3.10 | 3.18 | 3.40 | 3.60 | 3.80 | 3.97 | 4.15 | 4.34 | 4.54 | 4.75 | 4.96 | 5.19 |
| | | 3.60 | 4.00 | 4.35 | 4.73 | 5.15 | 5.57 | 6.12 | 6.63 | 7.05 | 7.37 | 7.71 | 8.06 | 8.43 | 8.82 | 9.22 |
| Wisconsin Energy Corporation | WEC | 3.33 | 3.48 | 3.64 | 3.80 | 3.96 | 4.32 | 4.65 | 4.93 | 5.16 | 5.39 | 5.64 | 5.90 | 6.17 | 6.45 | 6.74 |
| | | 4.60 | 4.90 | 5.21 | 5.55 | 5.90 | 6.25 | 6.84 | 7.37 | 7.82 | 8.18 | 8.56 | 8.95 | 9.36 | 9.79 | 10.23 |
| Xcel Energy Inc. | XEL | 2.22 | 2.36 | 2.50 | 2.66 | 2.82 | 3.09 | 3.34 | 3.55 | 3.71 | 3.88 | 4.06 | 4.24 | 4.44 | 4.64 | 4.85 |
| | | 3.35 | 3.55 | 3.77 | 4.00 | 4.25 | 4.50 | 4.92 | 5.30 | 5.63 | 5.88 | 6.15 | 6.43 | 6.73 | 7.04 | 7.36 |

Company Proxy Group - Mean
Staff Proxy Group - Mean

| [1] | [2] | [32] | [33] | [34] | [35] | [36] | [37] | [38] | [39] | [40] | [41] | [42] | [43] | [44] | [45] | [46] | [47] | [48] | [49] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | B.O.Y. Cash Flows | | | | | | | | | |
| | | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 | 2048 | 2049 | 2050 | 2051 | 2052 | 2051 | 2051 | 2052 |
| Company | Ticker | Final Stage | | | | | | | | | | | | | | Terminal Value | | Sale | |
| Alliant Energy Corporation | LNT | 4.32 | 4.52 | 4.73 | 4.94 | 5.17 | 5.41 | 5.65 | 5.91 | 6.18 | 6.47 | 6.76 | 7.07 | 7.40 | 7.73 | 251.49 | 8.09 | 243.40 | |
| | | 7.13 | 7.46 | 7.80 | 8.16 | 8.53 | 8.92 | 9.33 | 9.76 | 10.20 | 10.67 | 11.16 | 11.67 | 12.20 | 12.76 | | 13.35 | | 13.96 |
| Ameren Corporation | AEE | 6.41 | 6.70 | 7.01 | 7.33 | 7.66 | 8.01 | 8.38 | 8.76 | 9.16 | 9.58 | 10.02 | 10.48 | 10.96 | 11.46 | 323.35 | 11.99 | 311.36 | |
| | | 9.90 | 10.36 | 10.83 | 11.33 | 11.84 | 12.39 | 12.95 | 13.55 | 14.17 | 14.81 | 15.49 | 16.20 | 16.94 | 17.72 | | 18.53 | | 19.38 |
| American Electric Power Company, Inc. | AEP | 7.78 | 8.14 | 8.51 | 8.90 | 9.31 | 9.74 | 10.18 | 10.65 | 11.13 | 11.64 | 12.18 | 12.73 | 13.32 | 13.93 | 378.37 | 14.56 | 363.81 | |
| | | 12.32 | 12.88 | 13.47 | 14.09 | 14.73 | 15.41 | 16.11 | 16.85 | 17.62 | 18.43 | 19.27 | 20.15 | 21.08 | 22.04 | | 23.05 | | 24.10 |
| Avista Corporation | AVA | 4.02 | 4.20 | 4.39 | 4.59 | 4.80 | 5.02 | 5.25 | 5.49 | 5.74 | 6.01 | 6.28 | 6.57 | 6.87 | 7.18 | 159.77 | 7.51 | 152.25 | |
| | | 5.20 | 5.43 | 5.68 | 5.94 | 6.21 | 6.50 | 6.80 | 7.11 | 7.43 | 7.77 | 8.13 | 8.50 | 8.89 | 9.30 | | 9.72 | | 10.17 |
| Black Hills Corporation | BKH | 5.49 | 5.74 | 6.01 | 6.28 | 6.57 | 6.87 | 7.18 | 7.51 | 7.86 | 8.22 | 8.59 | 8.99 | 9.40 | 9.83 | 219.26 | 10.28 | 208.98 | |
| | | 7.67 | 8.03 | 8.39 | 8.78 | 9.18 | 9.60 | 10.04 | 10.50 | 10.98 | 11.48 | 12.01 | 12.56 | 13.13 | 13.73 | | 14.36 | | 15.02 |
| CMS Energy Corporation | CMS | 4.19 | 4.39 | 4.59 | 4.80 | 5.02 | 5.25 | 5.49 | 5.74 | 6.00 | 6.28 | 6.56 | 6.86 | 7.18 | 7.51 | 252.97 | 7.85 | 245.12 | |
| | | 6.64 | 6.95 | 7.26 | 7.60 | 7.94 | 8.31 | 8.69 | 9.09 | 9.50 | 9.94 | 10.39 | 10.87 | 11.37 | 11.89 | | 12.43 | | 13.00 |
| Consolidated Edison, Inc. | ED | 6.98 | 7.30 | 7.64 | 7.98 | 8.35 | 8.73 | 9.13 | 9.55 | 9.99 | 10.44 | 10.92 | 11.42 | 11.94 | 12.49 | 414.40 | 13.06 | 401.34 | |
| | | 11.05 | 11.56 | 12.09 | 12.64 | 13.22 | 13.82 | 14.46 | 15.12 | 15.81 | 16.53 | 17.29 | 18.08 | 18.91 | 19.77 | | 20.68 | | 21.63 |
| Duke Energy Corporation | DUK | 7.30 | 7.63 | 7.98 | 8.35 | 8.73 | 9.13 | 9.55 | 9.98 | 10.44 | 10.92 | 11.42 | 11.94 | 12.49 | 13.06 | 431.58 | 13.66 | 417.92 | |
| | | 12.37 | 12.94 | 13.53 | 14.15 | 14.80 | 15.47 | 16.18 | 16.92 | 17.70 | 18.51 | 19.35 | 20.24 | 21.17 | 22.13 | | 23.15 | | 24.21 |
| Entergy Corporation | ETR | 8.97 | 9.38 | 9.81 | 10.26 | 10.73 | 11.22 | 11.73 | 12.27 | 12.83 | 13.42 | 14.03 | 14.67 | 15.34 | 16.05 | 364.46 | 16.78 | 347.68 | |
| | | 12.81 | 13.40 | 14.01 | 14.65 | 15.33 | 16.03 | 16.76 | 17.53 | 18.33 | 19.17 | 20.05 | 20.96 | 21.92 | 22.93 | | 23.98 | | 25.07 |
| Evergy, Inc. | EVRG | 5.70 | 5.96 | 6.23 | 6.52 | 6.81 | 7.13 | 7.45 | 7.79 | 8.15 | 8.52 | 8.91 | 9.32 | 9.75 | 10.19 | 260.76 | 10.66 | 250.10 | |
| | | 8.99 | 9.41 | 9.84 | 10.29 | 10.76 | 11.25 | 11.76 | 12.30 | 12.87 | 13.45 | 14.07 | 14.71 | 15.39 | 16.09 | | 16.83 | | 17.60 |
| Fortis, Inc. | FTS | 5.12 | 5.35 | 5.59 | 5.85 | 6.12 | 6.40 | 6.69 | 7.00 | 7.32 | 7.65 | 8.00 | 8.37 | 8.75 | 9.15 | 195.07 | 9.57 | 185.50 | |
| | | 6.88 | 7.20 | 7.53 | 7.87 | 8.23 | 8.61 | 9.00 | 9.41 | 9.84 | 10.30 | 10.77 | 11.26 | 11.77 | 12.31 | | 12.88 | | 13.47 |
| IDACORP, Inc. | IDA | 7.92 | 8.28 | 8.66 | 9.05 | 9.47 | 9.90 | 10.36 | 10.83 | 11.33 | 11.84 | 12.39 | 12.95 | 13.55 | 14.17 | 393.67 | 14.81 | 378.86 | |
| | | 10.49 | 10.97 | 11.47 | 12.00 | 12.55 | 13.12 | 13.72 | 14.35 | 15.01 | 15.69 | 16.41 | 17.16 | 17.95 | 18.77 | | 19.63 | | 20.53 |
| NextEra Energy, Inc. | NEE | 4.19 | 4.38 | 4.58 | 4.79 | 5.01 | 5.24 | 5.48 | 5.73 | 5.99 | 6.27 | 6.55 | 6.85 | 7.17 | 7.49 | 310.59 | 7.84 | 302.75 | |
| | | 8.51 | 8.90 | 9.31 | 9.73 | 10.18 | 10.64 | 11.13 | 11.64 | 12.17 | 12.73 | 13.31 | 13.92 | 14.56 | 15.22 | | 15.92 | | 16.65 |
| NorthWestern Corporation | NWE | 4.74 | 4.95 | 5.18 | 5.42 | 5.66 | 5.92 | 6.19 | 6.48 | 6.77 | 7.08 | 7.41 | 7.75 | 8.10 | 8.47 | 208.44 | 8.86 | 199.58 | |
| | | 7.17 | 7.50 | 7.85 | 8.20 | 8.58 | 8.97 | 9.38 | 9.81 | 10.26 | 10.73 | 11.22 | 11.74 | 12.27 | 12.84 | | 13.42 | | 14.04 |
| OGE Energy Corporation | OGE | 3.17 | 3.32 | 3.47 | 3.63 | 3.80 | 3.97 | 4.15 | 4.34 | 4.54 | 4.75 | 4.97 | 5.19 | 5.43 | 5.68 | 200.14 | 5.94 | 194.20 | |
| | | 6.02 | 6.29 | 6.58 | 6.88 | 7.20 | 7.53 | 7.87 | 8.23 | 8.61 | 9.00 | 9.41 | 9.84 | 10.29 | 10.77 | | 11.26 | | 11.77 |
| Pinnacle West Capital Corporation | PNW | 6.45 | 6.75 | 7.06 | 7.38 | 7.72 | 8.07 | 8.44 | 8.83 | 9.23 | 9.65 | 10.09 | 10.56 | 11.04 | 11.54 | 342.28 | 12.07 | 330.21 | |
| | | 9.98 | 10.43 | 10.91 | 11.41 | 11.93 | 12.48 | 13.05 | 13.65 | 14.27 | 14.92 | 15.61 | 16.32 | 17.07 | 17.85 | | 18.67 | | 19.52 |
| Portland General Electric Company | POR | 4.45 | 4.65 | 4.87 | 5.09 | 5.32 | 5.57 | 5.82 | 6.09 | 6.37 | 6.66 | 6.96 | 7.28 | 7.61 | 7.96 | 204.38 | 8.33 | 196.06 | |
| | | 6.52 | 6.82 | 7.14 | 7.46 | 7.80 | 8.16 | 8.53 | 8.93 | 9.33 | 9.76 | 10.21 | 10.68 | 11.16 | 11.67 | | 12.21 | | 12.77 |
| PPL Corporation | PPL | 2.12 | 2.21 | 2.31 | 2.42 | 2.53 | 2.65 | 2.77 | 2.89 | 3.03 | 3.17 | 3.31 | 3.46 | 3.62 | 3.79 | 135.99 | 3.96 | 132.03 | |
| | | 3.94 | 4.12 | 4.31 | 4.50 | 4.71 | 4.93 | 5.15 | 5.39 | 5.63 | 5.89 | 6.16 | 6.44 | 6.74 | 7.05 | | 7.37 | | 7.71 |
| Public Service Enterprise Group Inc. | PEG | 5.26 | 5.50 | 5.75 | 6.01 | 6.29 | 6.57 | 6.87 | 7.19 | 7.52 | 7.86 | 8.22 | 8.60 | 8.99 | 9.40 | 263.95 | 9.83 | 254.12 | |
| | | 7.69 | 8.04 | 8.41 | 8.80 | 9.20 | 9.62 | 10.06 | 10.52 | 11.00 | 11.51 | 12.03 | 12.59 | 13.16 | 13.76 | | 14.39 | | 15.05 |
| Sempra Energy | SRE | 5.10 | 5.34 | 5.58 | 5.84 | 6.10 | 6.38 | 6.68 | 6.98 | 7.30 | 7.64 | 7.99 | 8.35 | 8.73 | 9.13 | 357.13 | 9.55 | 347.58 | |
| | | 11.02 | 11.52 | 12.05 | 12.60 | 13.18 | 13.78 | 14.41 | 15.07 | 15.76 | 16.48 | 17.24 | 18.03 | 18.85 | 19.71 | | 20.62 | | 21.56 |
| Southern Company | SO | 5.43 | 5.68 | 5.94 | 6.21 | 6.49 | 6.79 | 7.10 | 7.43 | 7.77 | 8.12 | 8.49 | 8.88 | 9.29 | 9.72 | 375.96 | 10.16 | 365.80 | |
| | | 9.64 | 10.08 | 10.54 | 11.03 | 11.53 | 12.06 | 12.61 | 13.19 | 13.79 | 14.42 | 15.08 | 15.77 | 16.50 | 17.25 | | 18.04 | | 18.87 |
| Wisconsin Energy Corporation | WEC | 7.05 | 7.38 | 7.71 | 8.07 | 8.43 | 8.82 | 9.22 | 9.65 | 10.09 | 10.55 | 11.03 | 11.54 | 12.07 | 12.62 | 386.08 | 13.20 | 372.88 | |
| | | 10.70 | 11.19 | 11.71 | 12.24 | 12.80 | 13.39 | 14.00 | 14.64 | 15.31 | 16.01 | 16.74 | 17.51 | 18.31 | 19.15 | | 20.03 | | 20.94 |
| Xcel Energy Inc. | XEL | 5.07 | 5.31 | 5.55 | 5.80 | 6.07 | 6.35 | 6.64 | 6.94 | 7.26 | 7.59 | 7.94 | 8.30 | 8.68 | 9.08 | 282.44 | 9.50 | 272.94 | |
| | | 7.70 | 8.05 | 8.42 | 8.80 | 9.20 | 9.63 | 10.07 | 10.53 | 11.01 | 11.51 | 12.04 | 12.59 | 13.17 | 13.77 | | 14.40 | | 15.06 |

Company Proxy Group - Mean
Staff Proxy Group - Mean

Docket No. UE 433
Exhibit PAC/2214
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Adjustment to Staff Model Results Summary**

**July 2024**

Staff ROE Summary - As Filed

| Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Y | SSA | 4.39% | CBO | 4.46% | Composite | 4.58% | Historical | 5.10% | PAC | 5.51% |
| Company Proxy Group | 8.88% | | 8.94% | | 9.04% | | 9.47% | | 9.81% | |
| Staff Proxy Group | 9.08% | | 9.14% | | 9.24% | | 9.67% | | 10.01% | |

| Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity (Hamada Adjusted) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Y | SSA | 4.39% | CBO | 4.46% | Composite | 4.58% | Historical | 5.10% | PAC | 5.51% |
| Company Proxy Group | 8.47% | | 8.52% | | 8.62% | | 9.06% | | 9.40% | |
| Staff Proxy Group | 8.97% | | 9.02% | | 9.12% | | 9.56% | | 9.89% | |

| Model Y: 3 Stage DCF - Dividend Growth with Terminal Value as Sales based upon EPS Growth and Terminal Stock Sale | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Y | SSA | 4.39% | CBO | 4.46% | Composite | 4.58% | Historical | 5.10% | PAC | 5.51% |
| Company Proxy Group | 9.20% | | 9.25% | | 9.34% | | 9.74% | | 10.05% | |
| Staff Proxy Group | 9.40% | | 9.45% | | 9.54% | | 9.93% | | 10.24% | |

| Model Y: 3 Stage DCF - Dividend & EPS Growth with Terminal Value as Stock Sale (Hamada Adjusted) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Y | SSA | 4.39% | CBO | 4.46% | Composite | 4.58% | Historical | 5.10% | PAC | 5.51% |
| Company Proxy Group | 8.78% | | 8.83% | | 8.92% | | 9.33% | | 9.63% | |
| Staff Proxy Group | 9.28% | | 9.33% | | 9.42% | | 9.82% | | 10.13% | |

| | | | | | |
|---|---|---|---|---|---|
| Best Fit Range of Reasonable ROEs | 8.97% | to | 9.42% | ROE | |
| Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by : | | | | **12.5** | **bps** |
| | **9.09%** | **to** | **9.55%** | **ROE** | |
| | **Midpoint** | **9.32%** | **ROE** | **Testimony** | |

Notes:
[1] The results for the Company proxy group do not tie to Mr. Muldoon's filed exhibits. PPL and ALE were excluded. ALE was excluded due to M&A activity and PPL was excluded because PPL was not included in the proxy group in Ms. Bulkley's Direct Testimony. Mr. Muldoon incorrectly included PPL in the Company proxy group.

Staff ROE Summary - Adjusted (Historical GDP Growth Rate)

| Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Y | SSA | 4.39% | CBO | 4.46% | Composite | 4.58% | Historical | 5.10% | PAC | 5.51% |
| Company Proxy Group | 8.88% | | 8.94% | | 9.04% | | 9.47% | | 9.81% | |
| Staff Proxy Group | 9.08% | | 9.14% | | 9.24% | | 9.67% | | 10.01% | |

| Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity (Hamada Adjusted) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Y | SSA | 4.39% | CBO | 4.46% | Composite | 4.58% | Historical | 5.10% | PAC | 5.51% |
| Company Proxy Group | 8.47% | | 8.52% | | 8.62% | | 9.06% | | 9.40% | |
| Staff Proxy Group | 8.97% | | 9.02% | | 9.12% | | 9.56% | | 9.89% | |

| Model Y: 3 Stage DCF - Dividend Growth with Terminal Value as Sales based upon EPS Growth and Terminal Stock Sale | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Y | SSA | 4.39% | CBO | 4.46% | Composite | 4.58% | Historical | 5.10% | PAC | 5.51% |
| Company Proxy Group | 9.20% | | 9.25% | | 9.34% | | 9.74% | | 10.05% | |
| Staff Proxy Group | 9.40% | | 9.45% | | 9.54% | | 9.93% | | 10.24% | |

| Model Y: 3 Stage DCF - Dividend & EPS Growth with Terminal Value as Stock Sale (Hamada Adjusted) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Y | SSA | 4.39% | CBO | 4.46% | Composite | 4.58% | Historical | 5.10% | PAC | 5.51% |
| Company Proxy Group | 8.78% | | 8.83% | | 8.92% | | 9.33% | | 9.63% | |
| Staff Proxy Group | 9.28% | | 9.33% | | 9.42% | | 9.82% | | 10.13% | |

| | | | | | |
|---|---|---|---|---|---|
| Best Fit Range of Reasonable ROEs | 9.06% | to | 9.82% | ROE | |
| Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by : | | | | **12.5** | **bps** |
| | **9.18%** | **to** | **9.94%** | **ROE** | |
| | **Midpoint** | **9.56%** | **ROE** | **Testimony** | |

Staff ROE Summary - Adjusted (Hamada Adjustment)

| Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Y | SSA | 4.39% | CBO | 4.46% | Composite | 4.58% | Historical | 5.10% | PAC | 5.51% |
| Company Proxy Group | 8.88% | | 8.94% | | 9.04% | | 9.47% | | 9.81% | |
| Staff Proxy Group | 9.08% | | 9.14% | | 9.24% | | 9.67% | | 10.01% | |

| Model Y: 3 Stage DCF - Dividend Growth with Terminal Value as Sales based upon EPS Growth and Terminal Stock Sale | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Y | SSA | 4.39% | CBO | 4.46% | Composite | 4.58% | Historical | 5.10% | PAC | 5.51% |
| Company Proxy Group | 9.20% | | 9.25% | | 9.34% | | 9.74% | | 10.05% | |
| Staff Proxy Group | 9.40% | | 9.45% | | 9.54% | | 9.93% | | 10.24% | |

| | | | | | |
|---|---|---|---|---|---|
| Best Fit Range of Reasonable ROEs | 9.54% | to | 9.99% | ROE | |
| Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by : | | | | **12.5** | **bps** |
| | **9.67%** | **to** | **10.12%** | **ROE** | |
| | **Midpoint** | **9.89%** | **ROE** | **Testimony** | |

| Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity (Hamada Adjusted) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Y | SSA | 4.39% | CBO | 4.46% | Composite | 4.58% | Historical | 5.10% | PAC | 5.51% |
| Company Proxy Group | 9.28% | | 9.34% | | 9.44% | | 9.88% | | 10.21% | |
| Staff Proxy Group | 9.54% | | 9.60% | | 9.69% | | 10.13% | | 10.46% | |

| Model Y: 3 Stage DCF - Dividend & EPS Growth with Terminal Value as Stock Sale (Hamada Adjusted) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Y | SSA | 4.39% | CBO | 4.46% | Composite | 4.58% | Historical | 5.10% | PAC | 5.51% |
| Company Proxy Group | 9.60% | | 9.65% | | 9.74% | | 10.14% | | 10.45% | |
| Staff Proxy Group | 9.85% | | 9.90% | | 9.99% | | 10.39% | | 10.70% | |

Staff ROE Summary - Adjusted (Historical GDP Growth Rate & Hamada Adjustment)

| Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Y | SSA | 4.39% | CBO | 4.46% | Composite | 4.58% | Historical | 5.10% | PAC | 5.51% |
| Company Proxy Group | 8.88% | | 8.94% | | 9.04% | | 9.47% | | 9.81% | |
| Staff Proxy Group | 9.08% | | 9.14% | | 9.24% | | 9.67% | | 10.01% | |

| Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity (Hamada Adjusted) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Y | SSA | 4.39% | CBO | 4.46% | Composite | 4.58% | Historical | 5.10% | PAC | 5.51% |
| Company Proxy Group | 9.28% | | 9.34% | | 9.44% | | 9.88% | | 10.21% | |
| Staff Proxy Group | 9.54% | | 9.60% | | 9.69% | | 10.13% | | 10.46% | |

| Model Y: 3 Stage DCF - Dividend Growth with Terminal Value as Sales based upon EPS Growth and Terminal Stock Sale | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Y | SSA | 4.39% | CBO | 4.46% | Composite | 4.58% | Historical | 5.10% | PAC | 5.51% |
| Company Proxy Group | 9.20% | | 9.25% | | 9.34% | | 9.74% | | 10.05% | |
| Staff Proxy Group | 9.40% | | 9.45% | | 9.54% | | 9.93% | | 10.24% | |

| Model Y: 3 Stage DCF - Dividend & EPS Growth with Terminal Value as Stock Sale (Hamada Adjusted) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Y | SSA | 4.39% | CBO | 4.46% | Composite | 4.58% | Historical | 5.10% | PAC | 5.51% |
| Company Proxy Group | 9.60% | | 9.65% | | 9.74% | | 10.14% | | 10.45% | |
| Staff Proxy Group | 9.85% | | 9.90% | | 9.99% | | 10.39% | | 10.70% | |

Best Fit Range of Reasonable ROEs 9.88% to 10.39% ROE

Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by : **12.5** **bps**

**10.00%** **to** **10.52%** **ROE**

**Midpoint** **10.26%** **ROE** **Testimony**

Docket No. UE 433
Exhibit PAC/2215
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Market Value Capital Structures - Staff and Bulkley Proxy Group**

**July 2024**

**Market Value of the Capital Structure of Company and Staff Proxy Groups**

Expressed in ($000s)

| | | | | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] | [13] | [14] | [15] | [16] | [17] | [18] | [19] | [20] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Debt | | | | | | | | | | | | Preferred Equity | | Common Equity | | Market Value | | | |
| Company | Ticker | Company Proxy Group | Staff Proxy Group | Current Assets | Current Liabilities | Current Long-Term Debt and Leases | Net Working Capital | Short-Term Debt | Short-Term Debt Adj'd for Net Working Capital | Long-Term Debt | Book Value of Total Debt | Market Value of Long-Term Debt | Carrying Amount of Long-Term Debt | Adjustment to Book Value of Long-Term Debt | Market Value of Total Debt | Book Value of Preferred Equity | Market Value of Preferred Equity | Book Value of Common Equity | Market Value of Common Equity | Market Value Of the Firm | Debt Ratio | Preferred Equity Ratio | Common Equity Ratio |
| Alliant Energy Corporation | LNT | Yes | Yes | $1,272,000 | $2,304,000 | $811,000 | ($221,000) | $475,000 | $221,000 | $8,418,000 | $9,450,000 | $8,677,000 | $9,034,000 | -$357,000 | $9,093,000 | $0 | $0 | $ 6,777,000 | $ 13,090,687 | $22,183,687 | 40.99% | 0.00% | 59.01% |
| Ameren Corporation | AEE | Yes | Yes | $2,181,000 | $3,345,000 | $849,000 | ($315,000) | $536,000 | $315,000 | $15,121,000 | $16,285,000 | $14,833,000 | $15,970,000 | -$1,137,000 | $15,148,000 | $0 | $0 | $ 11,349,000 | $ 19,021,445 | $34,169,445 | 44.33% | 0.00% | 55.67% |
| American Electric Power Compa | AEP | Yes | | $6,082,100 | $11,583,600 | $2,722,400 | ($2,779,100) | $2,830,200 | $2,779,100 | $ 38,368,900 | $43,870,400 | $37,325,700 | $40,143,200 | -$2,817,500 | $41,052,900 | $0 | $0 | $ 25,246,700 | $ 42,711,619 | $83,764,519 | 49.01% | 0.00% | 50.99% |
| Avista Corporation | AVA | Yes | Yes | $661,842 | $775,205 | $22,890 | ($90,473) | $349,000 | $90,473 | $2,693,311 | $2,806,674 | $2,221,103 | $2,644,042 | -$422,939 | $2,383,735 | $0 | $0 | $ 2,485,323 | $ 2,765,118 | $5,148,853 | 46.30% | 0.00% | 53.70% |
| Black Hills Corporation | BKH | | Yes | $826,600 | $1,185,100 | $600,000 | $241,500 | $0 | $0 | $3,801,200 | $4,401,200 | $4,215,600 | $4,401,200 | -$185,600 | $4,215,600 | $0 | $0 | $ 3,215,300 | $ 3,668,149 | $7,883,749 | 53.47% | 0.00% | 46.53% |
| CMS Energy Corporation | CMS | Yes | | $2,839,000 | $2,895,000 | $984,000 | $928,000 | $93,000 | $0 | $14,592,000 | $15,576,000 | $14,316,000 | $15,494,000 | -$1,178,000 | $14,398,000 | $224,000 | $224,000 | $ 7,320,000 | $ 16,942,710 | $31,564,710 | 45.61% | 0.71% | 53.68% |
| Consolidated Edison, Inc. | ED | | Yes | $6,537,000 | $6,462,000 | $367,000 | $442,000 | $2,288,000 | $0 | $22,357,000 | $22,724,000 | $20,525,000 | $22,177,000 | -$1,652,000 | $21,072,000 | $0 | $0 | $ 21,158,000 | $ 31,404,643 | $52,476,643 | 40.16% | 0.00% | 59.84% |
| Duke Energy Corporation | DUK | Yes | | $12,769,000 | $17,283,000 | $2,988,000 | ($1,526,000) | $4,288,000 | $1,526,000 | $73,369,000 | $77,883,000 | $69,790,000 | $75,252,000 | -$5,462,000 | $72,421,000 | $1,962,000 | $1,962,000 | $ 47,150,000 | $ 74,789,866 | $149,172,866 | 48.55% | 1.32% | 50.14% |
| Entergy Corporation | ETR | Yes | | $3,660,869 | $6,396,492 | $2,176,517 | ($559,106) | $1,138,171 | $559,106 | $23,227,681 | $25,963,304 | $22,489,174 | $25,107,896 | -$2,618,722 | $23,344,582 | $0 | $0 | $ 14,622,647 | $ 21,398,960 | $44,743,542 | 52.17% | 0.00% | 47.83% |
| Evergy, Inc. | EVRG | Yes | Yes | $1,789,100 | $3,512,600 | $825,300 | ($898,200) | $1,293,800 | $898,200 | $11,154,100 | $12,877,600 | $11,044,900 | $11,853,300 | -$808,400 | $12,069,200 | $0 | $0 | $ 9,663,100 | $ 11,991,424 | $24,060,624 | 50.16% | 0.00% | 49.84% |
| Fortis, Inc. | FTS | | Yes | $3,047,788 | $4,516,026 | $1,749,922 | $281,684 | $90,109 | $0 | $20,908,960 | $22,658,883 | $21,126,271 | $22,489,256 | -$1,362,985 | $21,295,897 | $1,228,959 | $1,228,959 | $ 15,054,936 | $ 20,162,274 | $42,687,130 | 49.89% | 2.88% | 47.23% |
| IDACORP, Inc. | IDA | Yes | Yes | $1,004,054 | $634,076 | $49,800 | $419,778 | $0 | $0 | $2,775,790 | $2,825,590 | $2,684,278 | $2,825,590 | -$141,312 | $2,684,278 | $0 | $0 | $ 2,907,569 | $ 4,976,490 | $7,660,768 | 35.04% | 0.00% | 64.96% |
| NextEra Energy, Inc. | NEE | Yes | | $15,361,000 | $27,963,000 | $6,901,000 | ($5,701,000) | $4,905,000 | $4,905,000 | $62,261,000 | $74,067,000 | $64,103,000 | $68,306,000 | -$4,203,000 | $69,864,000 | $0 | $0 | $ 47,468,000 | $ 124,620,728 | $194,484,728 | 35.92% | 0.00% | 64.08% |
| NorthWestern Corporation | NWE | Yes | Yes | $407,006 | $534,898 | $103,288 | ($24,604) | $0 | $0 | $2,690,096 | $2,793,384 | $2,521,030 | $2,784,585 | -$263,555 | $2,529,829 | $0 | $0 | $ 2,785,314 | $ 3,116,617 | $5,646,446 | 44.80% | 0.00% | 55.20% |
| OGE Energy Corporation | OGE | Yes | Yes | $771,500 | $1,179,200 | $3,700 | ($404,000) | $499,200 | $404,000 | $4,367,300 | $4,775,000 | $4,114,800 | $4,340,500 | -$225,700 | $4,549,300 | $0 | $0 | $ 4,511,600 | $ 6,996,038 | $11,545,338 | 39.40% | 0.00% | 60.60% |
| Pinnacle West Capital Corporati | PNW | Yes | Yes | $1,926,967 | $2,889,347 | $942,883 | ($19,497) | $609,500 | $19,497 | $8,750,811 | $9,713,191 | $6,767,000 | $7,680,000 | -$913,000 | $8,800,191 | $0 | $0 | $ 6,177,664 | $ 8,146,537 | $16,946,728 | 51.93% | 0.00% | 48.07% |
| Portland General Electric Compa | POR | Yes | Yes | $935,000 | $1,112,000 | $103,000 | ($74,000) | $146,000 | $74,000 | $4,237,000 | $4,414,000 | $3,705,000 | $3,999,000 | -$294,000 | $4,120,000 | $0 | $0 | $ 3,319,000 | $ 4,382,710 | $8,502,710 | 48.46% | 0.00% | 51.54% |
| PPL Corporation | PPL | | Yes | $2,932,000 | $3,340,000 | $24,000 | ($384,000) | $992,000 | $384,000 | $14,743,000 | $15,151,000 | $14,031,000 | $14,612,000 | -$581,000 | $14,570,000 | $0 | $0 | $ 13,933,000 | $ 19,976,071 | $34,546,071 | 42.18% | 0.00% | 57.82% |
| Public Service Enterprise Group | PEG | | Yes | $3,373,000 | $5,057,000 | $1,527,000 | ($157,000) | $949,000 | $157,000 | $17,957,000 | $19,641,000 | $17,950,000 | $19,284,000 | -$1,334,000 | $18,307,000 | $0 | $0 | $ 15,477,000 | $ 30,471,920 | $48,778,920 | 37.53% | 0.00% | 62.47% |
| Sempra Energy | SRE | | Yes | $5,470,000 | $10,090,000 | $1,045,000 | ($3,575,000) | $2,342,000 | $2,342,000 | $28,665,000 | $32,052,000 | $26,218,000 | $28,362,000 | -$2,144,000 | $29,908,000 | $889,000 | $889,000 | $ 27,786,000 | $ 47,029,686 | $77,826,686 | 38.43% | 1.14% | 60.43% |
| Southern Company | SO | Yes | | $10,432,000 | $13,467,000 | $2,659,000 | ($376,000) | $2,314,000 | $376,000 | $58,707,000 | $61,742,000 | $55,000,000 | $59,400,000 | -$4,400,000 | $57,342,000 | $0 | $0 | $ 31,444,000 | $ 76,474,229 | $133,816,229 | 42.85% | 0.00% | 57.15% |
| WEC Energy Group, Inc. | WEC | | Yes | $2,795,700 | $5,114,800 | $1,268,900 | ($1,050,200) | $2,020,900 | $1,050,200 | $15,551,600 | $17,870,700 | $15,564,300 | $16,631,100 | -$1,066,800 | $16,803,900 | $0 | $0 | $ 11,724,200 | $ 26,550,124 | $43,354,024 | 38.76% | 0.00% | 61.24% |
| Xcel Energy Inc. | XEL | Yes | | $4,069,000 | $5,652,000 | $797,000 | ($786,000) | $785,000 | $785,000 | $26,013,000 | $27,595,000 | $22,927,000 | $25,465,000 | -$2,538,000 | $25,057,000 | $0 | $0 | $ 17,616,000 | $ 34,162,948 | $59,219,948 | 42.31% | 0.00% | 57.69% |
| Company Proxy Group - Mean | | | | | | | | | | | | | | | | | | | | | 44.87% | 0.13% | 55.01% |
| Staff Proxy Group - Mean | | | | | | | | | | | | | | | | | | | | | 43.86% | 0.25% | 55.88% |

Notes:

[1] S&P Capital IQ Pro.
[2] S&P Capital IQ Pro.
[3] S&P Capital IQ Pro.
[4] Equals [1] - ([2] -[3])
[5] S&P Capital IQ Pro.
[6] Equals:
[A] 0 if [4] > 0
[B] ABS of [4] if [4] < 0 and ABS of [4] < [5]
[C] [5] if [4] < 0 and ABS of [4] > [5]
[7] S&P Capital IQ Pro.
[8] Equals [3] + [6] + [7]
[9] Company 10-Ks
[10] Company 10-Ks
[11] Equals [9] - [10]
[12] Equals [8] + [11]
[13] S&P Capital IQ Pro.
[14] Equals [13]
[15] S&P Capital IQ Pro.
[16] S&P Capital IQ Pro.
[17] Equals [12] + [14] + [16]
[18] Equals [12] / [17]
[19] Equals [14] / [17]
[20] Equals [16] / [17]
[21] FTS - Data Reported in CAD. S&P used an exchange rate of 0.757214 to convert to USD.

Docket No. UE 433
Exhibit PAC/2216
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Revised Staff CAPM Analysis**

**July 2024**

STAFF CAPM - AS FILED

| Company | Ticker | Company Proxy Group | Staff Proxy Group | [1] Current 30-day average of 30-year U.S. Treasury bond yield | [2] Value Line Beta | [3] Market Return | [4] Market Risk Premium | [5] CAPM ROE |
|---|---|---|---|---|---|---|---|---|
| Alliant Energy Corporation | LNT | Yes | Yes | 4.35% | 0.90 | 9.08% | 4.73% | 8.61% |
| Ameren Corporation | AEE | Yes | Yes | 4.35% | 0.90 | 9.08% | 4.73% | 8.61% |
| American Electric Power Company, Inc. | AEP | Yes | | 4.35% | 0.80 | 9.08% | 4.73% | 8.13% |
| Avista Corporation | AVA | Yes | Yes | 4.35% | 0.90 | 9.08% | 4.73% | 8.61% |
| Black Hills Corporation | BKH | | Yes | 4.35% | 1.00 | 9.08% | 4.73% | 9.08% |
| CMS Energy Corporation | CMS | Yes | | 4.35% | 0.85 | 9.08% | 4.73% | 8.37% |
| Consolidated Edison, Inc. | ED | | Yes | 4.35% | 0.75 | 9.08% | 4.73% | 7.90% |
| Duke Energy Corporation | DUK | Yes | | 4.35% | 0.85 | 9.08% | 4.73% | 8.37% |
| Entergy Corporation | ETR | Yes | | 4.35% | 0.95 | 9.08% | 4.73% | 8.84% |
| Evergy, Inc. | EVRG | Yes | Yes | 4.35% | 0.95 | 9.08% | 4.73% | 8.84% |
| Fortis, Inc. | FTS | | Yes | 4.35% | 0.70 | 9.08% | 4.73% | 7.66% |
| IDACORP, Inc. | IDA | Yes | Yes | 4.35% | 0.85 | 9.08% | 4.73% | 8.37% |
| NextEra Energy, Inc. | NEE | Yes | | 4.35% | 0.95 | 9.08% | 4.73% | 8.84% |
| NorthWestern Corporation | NWE | Yes | Yes | 4.35% | 0.95 | 9.08% | 4.73% | 8.84% |
| OGE Energy Corporation | OGE | Yes | Yes | 4.35% | 1.05 | 9.08% | 4.73% | 9.32% |
| Pinnacle West Capital Corporation | PNW | Yes | Yes | 4.35% | 0.95 | 9.08% | 4.73% | 8.84% |
| Portland General Electric Company | POR | Yes | Yes | 4.35% | 0.90 | 9.08% | 4.73% | 8.61% |
| PPL Corporation | PPL | | Yes | 4.35% | 1.05 | 9.08% | 4.73% | 9.32% |
| Public Service Enterprise Group Inc. | PEG | | Yes | 4.35% | 0.90 | 9.08% | 4.73% | 8.61% |
| Sempra Energy | SRE | | Yes | 4.35% | 1.00 | 9.08% | 4.73% | 9.08% |
| Southern Company | SO | Yes | | 4.35% | 0.90 | 9.08% | 4.73% | 8.61% |
| Wisconsin Energy Corporation | WEC | | Yes | 4.35% | 0.85 | 9.08% | 4.73% | 8.37% |
| Xcel Energy Inc. | XEL | Yes | | 4.35% | 0.85 | 9.08% | 4.73% | 8.37% |
| Company Proxy Group - Mean | | 16 | | | | | | 8.64% |
| Staff Proxy Group - Mean | | | 16 | | | | | 8.67% |

Notes:

[1] Source: Staff/105 Muldoon/1
[2] Source: Staff/105 Muldoon/1
[3] Source: Staff/105 Muldoon/1
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]

STAFF CAPM - ADJUSTED KROLL GEOMETRIC AVG. MARKET RETURN (1994-2023)

| Company | Ticker | Company Proxy Group | Staff Proxy Group | [1] Current 30-day average of 30-year U.S. Treasury bond yield | [2] Value Line Beta | [3] Market Return | [4] Market Risk Premium | [5] CAPM ROE |
|---|---|---|---|---|---|---|---|---|
| Alliant Energy Corporation | LNT | Yes | Yes | 4.35% | 0.90 | 10.31% | 5.96% | 9.71% |
| Ameren Corporation | AEE | Yes | Yes | 4.35% | 0.90 | 10.31% | 5.96% | 9.71% |
| American Electric Power Company, Inc. | AEP | Yes | | 4.35% | 0.80 | 10.31% | 5.96% | 9.12% |
| Avista Corporation | AVA | Yes | Yes | 4.35% | 0.90 | 10.31% | 5.96% | 9.71% |
| Black Hills Corporation | BKH | | Yes | 4.35% | 1.00 | 10.31% | 5.96% | 10.31% |
| CMS Energy Corporation | CMS | Yes | | 4.35% | 0.85 | 10.31% | 5.96% | 9.42% |
| Consolidated Edison, Inc. | ED | | Yes | 4.35% | 0.75 | 10.31% | 5.96% | 8.82% |
| Duke Energy Corporation | DUK | Yes | | 4.35% | 0.85 | 10.31% | 5.96% | 9.42% |
| Entergy Corporation | ETR | Yes | | 4.35% | 0.95 | 10.31% | 5.96% | 10.01% |
| Evergy, Inc. | EVRG | Yes | Yes | 4.35% | 0.95 | 10.31% | 5.96% | 10.01% |
| Fortis, Inc. | FTS | | Yes | 4.35% | 0.70 | 10.31% | 5.96% | 8.52% |
| IDACORP, Inc. | IDA | Yes | Yes | 4.35% | 0.85 | 10.31% | 5.96% | 9.42% |
| NextEra Energy, Inc. | NEE | Yes | | 4.35% | 0.95 | 10.31% | 5.96% | 10.01% |
| NorthWestern Corporation | NWE | Yes | Yes | 4.35% | 0.95 | 10.31% | 5.96% | 10.01% |
| OGE Energy Corporation | OGE | Yes | Yes | 4.35% | 1.05 | 10.31% | 5.96% | 10.61% |
| Pinnacle West Capital Corporation | PNW | Yes | Yes | 4.35% | 0.95 | 10.31% | 5.96% | 10.01% |
| Portland General Electric Company | POR | Yes | Yes | 4.35% | 0.90 | 10.31% | 5.96% | 9.71% |
| PPL Corporation | PPL | | Yes | 4.35% | 1.05 | 10.31% | 5.96% | 10.61% |
| Public Service Enterprise Group Inc. | PEG | | Yes | 4.35% | 0.90 | 10.31% | 5.96% | 9.71% |
| Sempra Energy | SRE | | Yes | 4.35% | 1.00 | 10.31% | 5.96% | 10.31% |
| Southern Company | SO | Yes | | 4.35% | 0.90 | 10.31% | 5.96% | 9.71% |
| Wisconsin Energy Corporation | WEC | | Yes | 4.35% | 0.85 | 10.31% | 5.96% | 9.42% |
| Xcel Energy Inc. | XEL | Yes | | 4.35% | 0.85 | 10.31% | 5.96% | 9.42% |
| Company Proxy Group - Mean | | 16 | | | | | | 9.75% |
| Staff Proxy Group - Mean | | | 16 | | | | | 9.79% |

Notes:

[1] Source: Staff/105 Muldoon/1

[2] Source: Staff/105 Muldoon/1

[3] Source: Kroll, Cost of Capital Navigator, data as of December 31, 2023

[4] Equals [3]-[1]

[5] Equals [1] + [2] x [4]

STAFF CAPM - ADJUSTED KROLL ARITHMETIC AVG. MARKET RETURN (1994-2023)

| Company | Ticker | Company Proxy Group | Staff Proxy Group | [1] Current 30-day average of 30-year U.S. Treasury bond yield | [2] Value Line Beta | [3] Market Return | [4] Market Risk Premium | [5] CAPM ROE |
|---|---|---|---|---|---|---|---|---|
| Alliant Energy Corporation | LNT | Yes | Yes | 4.35% | 0.90 | 11.94% | 7.59% | 11.18% |
| Ameren Corporation | AEE | Yes | Yes | 4.35% | 0.90 | 11.94% | 7.59% | 11.18% |
| American Electric Power Company, Inc. | AEP | Yes | | 4.35% | 0.80 | 11.94% | 7.59% | 10.42% |
| Avista Corporation | AVA | Yes | Yes | 4.35% | 0.90 | 11.94% | 7.59% | 11.18% |
| Black Hills Corporation | BKH | | Yes | 4.35% | 1.00 | 11.94% | 7.59% | 11.94% |
| CMS Energy Corporation | CMS | Yes | | 4.35% | 0.85 | 11.94% | 7.59% | 10.80% |
| Consolidated Edison, Inc. | ED | | Yes | 4.35% | 0.75 | 11.94% | 7.59% | 10.04% |
| Duke Energy Corporation | DUK | Yes | | 4.35% | 0.85 | 11.94% | 7.59% | 10.80% |
| Entergy Corporation | ETR | Yes | | 4.35% | 0.95 | 11.94% | 7.59% | 11.56% |
| Evergy, Inc. | EVRG | Yes | Yes | 4.35% | 0.95 | 11.94% | 7.59% | 11.56% |
| Fortis, Inc. | FTS | | Yes | 4.35% | 0.70 | 11.94% | 7.59% | 9.66% |
| IDACORP, Inc. | IDA | Yes | Yes | 4.35% | 0.85 | 11.94% | 7.59% | 10.80% |
| NextEra Energy, Inc. | NEE | Yes | | 4.35% | 0.95 | 11.94% | 7.59% | 11.56% |
| NorthWestern Corporation | NWE | Yes | Yes | 4.35% | 0.95 | 11.94% | 7.59% | 11.56% |
| OGE Energy Corporation | OGE | Yes | Yes | 4.35% | 1.05 | 11.94% | 7.59% | 12.32% |
| Pinnacle West Capital Corporation | PNW | Yes | Yes | 4.35% | 0.95 | 11.94% | 7.59% | 11.56% |
| Portland General Electric Company | POR | Yes | Yes | 4.35% | 0.90 | 11.94% | 7.59% | 11.18% |
| PPL Corporation | PPL | | Yes | 4.35% | 1.05 | 11.94% | 7.59% | 12.32% |
| Public Service Enterprise Group Inc. | PEG | | Yes | 4.35% | 0.90 | 11.94% | 7.59% | 11.18% |
| Sempra Energy | SRE | | Yes | 4.35% | 1.00 | 11.94% | 7.59% | 11.94% |
| Southern Company | SO | Yes | | 4.35% | 0.90 | 11.94% | 7.59% | 11.18% |
| Wisconsin Energy Corporation | WEC | | Yes | 4.35% | 0.85 | 11.94% | 7.59% | 10.80% |
| Xcel Energy Inc. | XEL | Yes | | 4.35% | 0.85 | 11.94% | 7.59% | 10.80% |
| Company Proxy Group - Mean | | 16 | | | | | | 11.23% |
| Staff Proxy Group - Mean | | | 16 | | | | | 11.28% |

Notes:

[1] Source: Staff/105 Muldoon/1

[2] Source: Staff/105 Muldoon/1

[3] Source: Kroll, Cost of Capital Navigator, data as of December 31, 2023

[4] Equals [3]-[1]

[5] Equals [1] + [2] x [4]

Docket No. UE 433
Exhibit PAC/2217
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Summary of the Effect of AWEC's Methodological Changes**

**July 2024**

**Summary of the Effect of AWEC's Methodological Changes**

***Constant Growth DCF***

**As Filed [1]**
11/30/2023

| | Mean | Median |
|---|---|---|
| 30-day | 9.24% | 9.27% |
| 90-day | 9.18% | 9.09% |
| 180-day | 8.99% | 8.96% |

**EPS Growth Rates from Value Line [2]**
11/30/2023

| | Mean | Median |
|---|---|---|
| 30-day | 10.03% | 10.13% |
| 90-day | 9.97% | 10.12% |
| 180-day | 9.78% | 10.01% |

**Decrease Resulting from Change in Methodology**

| | Mean | Median |
|---|---|---|
| 30-day | -0.79% | -0.86% |
| 90-day | -0.79% | -1.03% |
| 180-day | -0.79% | -1.05% |

**Update Data using UE-230172 Methodology**
6/30/2024

| Mean | Median |
|---|---|
| 10.15% | 10.58% |
| 10.09% | 10.58% |
| 9.89% | 10.30% |

Notes:
[1] AWEC/206 Kaufman/, Kaufman/8, Kaufman/9
[2] Kaufman Testimony Washington Utilities Transportation Commission, Docket UE-230172, LDK-4

***Multi Stage DCF***

**As Filed [1]**
11/30/2023

| | Mean | Median |
|---|---|---|
| 30-day | 9.45% | 9.48% |
| 90-day | 9.38% | 9.30% |
| 180-day | 9.15% | 9.16% |

**Long-term growth = Average T-Bond [2]**
11/30/2023

| | Mean | Median |
|---|---|---|
| 30-day | 9.91% | 9.94% |
| 90-day | 9.84% | 9.76% |
| 180-day | 9.62% | 9.63% |

**Decrease Resulting from Change in Methodology**

| | Mean | Median |
|---|---|---|
| 30-day | -0.46% | -0.45% |
| 90-day | -0.46% | -0.46% |
| 180-day | -0.47% | -0.47% |

**Long-term growth = Average T-Bond [2]**
6/30/2024

| Mean | Median |
|---|---|
| 9.79% | 9.53% |
| 9.97% | 9.79% |
| 10.09% | 9.99% |

Notes:
[1] AWEC/206, Kaufman/13, Kaufman/14, Kaufman/15
[2] Public Utilities Commission of Nevada Docket No. 24-02026, Exhibit Kaufman Direct-3 at 13-14.

***CAPM/ECAPM (Upper bound)***

**As Filed [1]**
11/30/2023

| | Mean | Median |
|---|---|---|
| CAPM | 9.88% | 9.85% |
| ECAPM | 10.30% | 10.29% |

**Bulkley Market Return Calculation [2]**
11/30/2023

| | Mean | Median |
|---|---|---|
| CAPM | 10.62% | 10.59% |
| ECAPM | 11.10% | 11.08% |

**Decrease Resulting from Change in Methodology**

| | Mean | Median |
|---|---|---|
| CAPM | -0.74% | -0.74% |
| ECAPM | -0.80% | -0.80% |

Notes:
[1] AWEC/206, Kaufman/39
[2] Kaufman Testimony Washington Utilities Transportation Commission, Exhibit LDK-1CT p. 22, ln 5.

Docket No. UE 433
Exhibit PAC/2218
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Summary of Adjustments to AWEC Multi-Stage DCF**

**July 2024**

**1. AWEC MSDCF Updated to use Treasury bond yield as GDP Growth Rate 11/30/2023**

| | GDP Growth Rate Scenario - 30-year Treasury bond yield 11-30-23 | | |
|---|---|---|---|
| | Minimum | Average | Maximum |
| 30-day | 9.35% | 9.91% | 10.49% |
| 90-day | 9.29% | 9.84% | 10.41% |
| 180-day | 9.08% | 9.62% | 10.17% |
| Mean | 9.24% | 9.79% | 10.36% |

**2. AWEC MSDCF Updated to use Treasury bond yield as GDP Growth Rate 6/30/2024**

| | Growth Rate Scenario- 30-year Treasury Bond yield 6-30-24 | | |
|---|---|---|---|
| | Minimum | Average | Maximum |
| 30-day | 9.30% | 9.79% | 10.24% |
| 90-day | 9.46% | 9.97% | 10.42% |
| 180-day | 9.57% | 10.09% | 10.55% |
| Mean | 9.44% | 9.95% | 10.40% |

**3. AWEC MSDCF Updated to use Staff Low GDP Growth Rate**

| | GDP Growth Rate Scenario- Staff low estimate | | |
|---|---|---|---|
| | Minimum | Average | Maximum |
| 30-day | 9.27% | 9.77% | 10.21% |
| 90-day | 9.44% | 9.94% | 10.40% |
| 180-day | 9.55% | 10.06% | 10.53% |
| Mean | 9.42% | 9.93% | 10.38% |

**4. AWEC MSDCF Updated to use Staff High GDP Growth Rate**

| | GDP Growth Rate Scenario- Staff High estimate | | |
|---|---|---|---|
| | Minimum | Average | Maximum |
| 30-day | 9.65% | 10.13% | 10.56% |
| 90-day | 9.81% | 10.30% | 10.74% |
| 180-day | 9.91% | 10.41% | 10.86% |
| Mean | 9.79% | 10.28% | 10.72% |

Docket No. UE 433
Exhibit PAC/2219
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**AWEC's Constant Growth DCF using their Prior Testimony Assumptions**

**July 2024**

**11/30/2023**

**30-DAY CONSTANT GROWTH DCF**

| Company | | [1] Annualized Dividend | [2] Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Value Line Projected EPS Growth Rate | [6] Cost of Equity: Minimum Growth Rate |
|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | $2.71 | $54.18 | 5.00% | 5.15% | 6.00% | 11.15% |
| Alliant Energy Corporation | LNT | $1.81 | $49.32 | 3.67% | 3.79% | 6.50% | 10.29% |
| Ameren Corporation | AEE | $2.52 | $76.88 | 3.28% | 3.38% | 6.50% | 9.88% |
| American Electric Power Company, Inc | AEP | $3.52 | $76.65 | 4.59% | 4.74% | 6.50% | 11.24% |
| Avista Corporation | AVA | $1.84 | $33.32 | 5.52% | 5.69% | 6.00% | 11.69% |
| CMS Energy Corporation | CMS | $1.95 | $55.46 | 3.52% | 3.63% | 6.50% | 10.13% |
| Duke Energy Corporation | DUK | $4.10 | $88.52 | 4.63% | 4.75% | 5.00% | 9.75% |
| Entergy Corporation | ETR | $4.52 | $96.53 | 4.68% | 4.69% | 0.50% | 5.19% |
| Evergy, Inc. | EVRG | $2.57 | $49.33 | 5.21% | 5.40% | 7.50% | 12.90% |
| IDACORP, Inc. | IDA | $3.32 | $96.12 | 3.45% | 3.52% | 4.00% | 7.52% |
| NextEra Energy, Inc. | NEE | $1.87 | $56.48 | 3.31% | 3.47% | 9.50% | 12.97% |
| NorthWestern Corporation | NWE | $2.56 | $49.46 | 5.18% | 5.27% | 3.50% | 8.77% |
| OGE Energy Corporation | OGE | $1.67 | $34.43 | 4.86% | 5.02% | 6.50% | 11.52% |
| Pinnacle West Capital Corporation | PNW | $3.52 | $72.98 | 4.82% | 4.88% | 2.50% | 7.38% |
| Portland General Electric Company | POR | $1.90 | $40.73 | 4.66% | 4.78% | 5.00% | 9.78% |
| Southern Company | SO | $2.80 | $68.05 | 4.11% | 4.25% | 6.50% | 10.75% |
| Xcel Energy Inc. | XEL | $2.08 | $59.77 | 3.48% | 3.58% | 6.00% | 9.58% |
| Mean | | | | | | | 10.03% |
| Median | | | | | | | 10.13% |

Notes:
[1] Bloomberg Professional as of November 30, 2023
[2] Bloomberg Professional 30-day average as of November 30, 2023
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[6] Equals [4] + [5]

**11/30/2023**

**90-DAY CONSTANT GROWTH DCF**

| Company | | [1] Annualized Dividend | [2] Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Value Line Projected EPS Growth Rate | [9] Cost of Equity: Minimum Growth Rate |
|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | $2.71 | $54.27 | 4.99% | 5.14% | 6.00% | 11.14% |
| Alliant Energy Corporation | LNT | $1.81 | $49.86 | 3.63% | 3.75% | 6.50% | 10.25% |
| Ameren Corporation | AEE | $2.52 | $78.29 | 3.22% | 3.32% | 6.50% | 9.82% |
| American Electric Power Company, Inc | AEP | $3.52 | $77.17 | 4.56% | 4.71% | 6.50% | 11.21% |
| Avista Corporation | AVA | $1.84 | $33.50 | 5.49% | 5.66% | 6.00% | 11.66% |
| CMS Energy Corporation | CMS | $1.95 | $55.55 | 3.51% | 3.62% | 6.50% | 10.12% |
| Duke Energy Corporation | DUK | $4.10 | $89.10 | 4.60% | 4.72% | 5.00% | 9.72% |
| Entergy Corporation | ETR | $4.52 | $95.22 | 4.75% | 4.76% | 0.50% | 5.26% |
| Evergy, Inc. | EVRG | $2.57 | $52.10 | 4.93% | 5.12% | 7.50% | 12.62% |
| IDACORP, Inc. | IDA | $3.32 | $95.86 | 3.46% | 3.53% | 4.00% | 7.53% |
| NextEra Energy, Inc. | NEE | $1.87 | $61.29 | 3.05% | 3.20% | 9.50% | 12.70% |
| NorthWestern Corporation | NWE | $2.56 | $50.42 | 5.08% | 5.17% | 3.50% | 8.67% |
| OGE Energy Corporation | OGE | $1.67 | $34.14 | 4.90% | 5.06% | 6.50% | 11.56% |
| Pinnacle West Capital Corporation | PNW | $3.52 | $75.15 | 4.68% | 4.74% | 2.50% | 7.24% |
| Portland General Electric Company | POR | $1.90 | $42.56 | 4.46% | 4.58% | 5.00% | 9.58% |
| Southern Company | SO | $2.80 | $67.52 | 4.15% | 4.28% | 6.50% | 10.78% |
| Xcel Energy Inc. | XEL | $2.08 | $58.79 | 3.54% | 3.64% | 6.00% | 9.64% |
| Mean | | | | | | | 9.97% |
| Median | | | | | | | 10.12% |

Notes:
[1] Bloomberg Professional as of November 30, 2023
[2] Bloomberg Professional 90-day average as of November 30, 2023
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[6] Equals [4] + [5]

**11/30/2023**

**180-DAY CONSTANT GROWTH DCF**

| Company | | [1] Annualized Dividend | [2] Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Value Line Projected EPS Growth Rate | [6] Cost of Equity: Minimum Growth Rate |
|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | $2.71 | $56.88 | 4.76% | 4.91% | 6.00% | 10.91% |
| Alliant Energy Corporation | LNT | $1.81 | $51.12 | 3.54% | 3.66% | 6.50% | 10.16% |
| Ameren Corporation | AEE | $2.52 | $81.27 | 3.10% | 3.20% | 6.50% | 9.70% |
| American Electric Power Company, Inc | AEP | $3.52 | $81.52 | 4.32% | 4.46% | 6.50% | 10.96% |
| Avista Corporation | AVA | $1.84 | $36.89 | 4.99% | 5.14% | 6.00% | 11.14% |
| CMS Energy Corporation | CMS | $1.95 | $57.38 | 3.40% | 3.51% | 6.50% | 10.01% |
| Duke Energy Corporation | DUK | $4.10 | $90.33 | 4.54% | 4.65% | 5.00% | 9.65% |
| Entergy Corporation | ETR | $4.52 | $97.81 | 4.62% | 4.63% | 0.50% | 5.13% |
| Evergy, Inc. | EVRG | $2.57 | $55.28 | 4.65% | 4.82% | 7.50% | 12.32% |
| IDACORP, Inc. | IDA | $3.32 | $100.25 | 3.31% | 3.38% | 4.00% | 7.38% |
| NextEra Energy, Inc. | NEE | $1.87 | $67.60 | 2.77% | 2.90% | 9.50% | 12.40% |
| NorthWestern Corporation | NWE | $2.56 | $53.59 | 4.78% | 4.86% | 3.50% | 8.36% |
| OGE Energy Corporation | OGE | $1.67 | $34.93 | 4.79% | 4.94% | 6.50% | 11.44% |
| Pinnacle West Capital Corporation | PNW | $3.52 | $76.59 | 4.60% | 4.65% | 2.50% | 7.15% |
| Portland General Electric Company | POR | $1.90 | $45.25 | 4.20% | 4.30% | 5.00% | 9.30% |
| Southern Company | SO | $2.80 | $68.47 | 4.09% | 4.22% | 6.50% | 10.72% |
| Xcel Energy Inc. | XEL | $2.08 | $61.98 | 3.36% | 3.46% | 6.00% | 9.46% |
| Mean | | | | | | | 9.78% |
| Median | | | | | | | 10.01% |

Notes:
[1] Bloomberg Professional as of November 30, 2023
[2] Bloomberg Professional 180-day average as of November 30, 2023
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[6] Equals [4] + [5]

**6/30/2024**

**30-DAY CONSTANT GROWTH DCF**

| Company | | [1] Annualized Dividend | [2] Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Value Line Projected EPS Growth Rate | [6] Cost of Equity: Minimum Growth Rate |
|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | $2.82 | $62.89 | 4.48% | 4.62% | 6.00% | 11.15% |
| Alliant Energy Corporation | LNT | $1.92 | $50.66 | 3.79% | 3.90% | 6.00% | 9.79% |
| Ameren Corporation | AEE | $2.68 | $71.34 | 3.76% | 3.88% | 6.50% | 9.88% |
| American Electric Power Company, Inc | AEP | $3.52 | $89.01 | 3.95% | 4.08% | 6.50% | 11.24% |
| Avista Corporation | AVA | $1.90 | $35.62 | 5.33% | 5.49% | 6.00% | 11.69% |
| CMS Energy Corporation | CMS | $2.06 | $60.92 | 3.38% | 3.47% | 5.00% | 8.63% |
| Duke Energy Corporation | DUK | $4.10 | $101.95 | 4.02% | 4.12% | 5.00% | 9.75% |
| Entergy Corporation | ETR | $4.52 | $108.95 | 4.15% | 4.16% | 0.50% | 5.19% |
| Evergy, Inc. | EVRG | $2.57 | $53.56 | 4.80% | 4.98% | 7.50% | 12.90% |
| IDACORP, Inc. | IDA | $3.32 | $93.69 | 3.54% | 3.63% | 5.00% | 8.52% |
| NextEra Energy, Inc. | NEE | $2.06 | $74.85 | 2.75% | 2.86% | 8.00% | 11.47% |
| NorthWestern Corporation | NWE | $2.60 | $50.34 | 5.16% | 5.27% | 4.00% | 9.27% |
| OGE Energy Corporation | OGE | $1.67 | $35.77 | 4.68% | 4.83% | 6.50% | 11.52% |
| Pinnacle West Capital Corporation | PNW | $3.52 | $76.61 | 4.59% | 4.70% | 4.50% | 9.38% |
| Portland General Electric Company | POR | $2.00 | $43.02 | 4.65% | 4.79% | 6.00% | 10.78% |
| Southern Company | SO | $2.88 | $78.61 | 3.66% | 3.78% | 6.50% | 10.75% |
| Xcel Energy Inc. | XEL | $2.19 | $54.15 | 4.04% | 4.19% | 7.00% | 10.58% |
| Mean | | | | | | | 10.15% |
| Median | | | | | | | 10.58% |

Notes:
[1] Bloomberg Professional as of June 30, 2024
[2] Bloomberg Professional 30-day average as of June 30, 2024
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[6] Equals [4] + [5]

**6/30/2024**

**90-DAY CONSTANT GROWTH DCF**

| Company | | [1] Annualized Dividend | [2] Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Value Line Projected EPS Growth Rate | [9] Cost of Equity: Minimum Growth Rate |
|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | $2.82 | $59.98 | 4.70% | 4.84% | 6.00% | 11.14% |
| Alliant Energy Corporation | LNT | $1.92 | $49.53 | 3.88% | 3.99% | 6.00% | 9.75% |
| Ameren Corporation | AEE | $2.68 | $71.82 | 3.73% | 3.85% | 6.50% | 9.82% |
| American Electric Power Company, Inc | AEP | $3.52 | $85.75 | 4.11% | 4.24% | 6.50% | 11.21% |
| Avista Corporation | AVA | $1.90 | $34.85 | 5.45% | 5.61% | 6.00% | 11.66% |
| CMS Energy Corporation | CMS | $2.06 | $59.65 | 3.45% | 3.54% | 5.00% | 8.62% |
| Duke Energy Corporation | DUK | $4.10 | $97.53 | 4.20% | 4.31% | 5.00% | 9.72% |
| Entergy Corporation | ETR | $4.52 | $105.61 | 4.28% | 4.29% | 0.50% | 5.26% |
| Evergy, Inc. | EVRG | $2.57 | $52.07 | 4.94% | 5.12% | 7.50% | 12.62% |
| IDACORP, Inc. | IDA | $3.32 | $92.22 | 3.60% | 3.69% | 5.00% | 8.53% |
| NextEra Energy, Inc. | NEE | $2.06 | $66.86 | 3.08% | 3.20% | 8.00% | 11.20% |
| NorthWestern Corporation | NWE | $2.60 | $49.38 | 5.27% | 5.37% | 4.00% | 9.17% |
| OGE Energy Corporation | OGE | $1.67 | $34.52 | 4.85% | 5.00% | 6.50% | 11.56% |
| Pinnacle West Capital Corporation | PNW | $3.52 | $73.66 | 4.78% | 4.89% | 4.50% | 9.24% |
| Portland General Electric Company | POR | $2.00 | $41.88 | 4.78% | 4.92% | 6.00% | 10.58% |
| Southern Company | SO | $2.88 | $73.26 | 3.93% | 4.06% | 6.50% | 10.78% |
| Xcel Energy Inc. | XEL | $2.19 | $53.46 | 4.10% | 4.24% | 7.00% | 10.64% |
| Mean | | | | | | | 10.09% |
| Median | | | | | | | 10.58% |

Notes:
[1] Bloomberg Professional as of June 30, 2024
[2] Bloomberg Professional 90-day average as of June 30, 2024
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[6] Equals [4] + [5]

**6/30/2024**

**180-DAY CONSTANT GROWTH DCF**

| Company | | [1] Annualized Dividend | [2] Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Value Line Projected EPS Growth Rate | [6] Cost of Equity: Minimum Growth Rate |
|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | $2.82 | $58.13 | 4.85% | 5.00% | 6.00% | 10.91% |
| Alliant Energy Corporation | LNT | $1.92 | $49.21 | 3.90% | 4.02% | 6.00% | 9.66% |
| Ameren Corporation | AEE | $2.68 | $72.14 | 3.71% | 3.84% | 6.50% | 9.70% |
| American Electric Power Company, Inc | AEP | $3.52 | $81.37 | 4.33% | 4.47% | 6.50% | 10.96% |
| Avista Corporation | AVA | $1.90 | $34.01 | 5.59% | 5.75% | 6.00% | 11.14% |
| CMS Energy Corporation | CMS | $2.06 | $57.67 | 3.57% | 3.66% | 5.00% | 8.51% |
| Duke Energy Corporation | DUK | $4.10 | $94.20 | 4.35% | 4.46% | 5.00% | 9.65% |
| Entergy Corporation | ETR | $4.52 | $101.22 | 4.47% | 4.48% | 0.50% | 5.13% |
| Evergy, Inc. | EVRG | $2.57 | $50.70 | 5.07% | 5.26% | 7.50% | 12.32% |
| IDACORP, Inc. | IDA | $3.32 | $93.06 | 3.57% | 3.66% | 5.00% | 8.38% |
| NextEra Energy, Inc. | NEE | $2.06 | $61.96 | 3.32% | 3.46% | 8.00% | 10.90% |
| NorthWestern Corporation | NWE | $2.60 | $48.68 | 5.34% | 5.45% | 4.00% | 8.86% |
| OGE Energy Corporation | OGE | $1.67 | $34.06 | 4.91% | 5.07% | 6.50% | 11.44% |
| Pinnacle West Capital Corporation | PNW | $3.52 | $72.08 | 4.88% | 4.99% | 4.50% | 9.15% |
| Portland General Electric Company | POR | $2.00 | $41.10 | 4.87% | 5.01% | 6.00% | 10.30% |
| Southern Company | SO | $2.88 | $70.45 | 4.09% | 4.22% | 6.50% | 10.72% |
| Xcel Energy Inc. | XEL | $2.19 | $56.13 | 3.90% | 4.04% | 7.00% | 10.46% |
| Mean | | | | | | | 9.89% |
| Median | | | | | | | 10.30% |

Notes:
[1] Bloomberg Professional as of June 30, 2024
[2] Bloomberg Professional 180-day average as of June 30, 2024
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[6] Equals [4] + [5]

Docket No. UE 433
Exhibit PAC/2220
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**AWEC's CAPM and ECAPM Using Prior Testimony Assumptions**

**July 2024**

**AWEC CAPITAL ASSET PRICING MODEL (AWEC/406)**
**PROJECTED RISK FREE RATE, AWEC ADJUSTED MARKET RETURN AND BETA ADJUSTED TO INDUSTRY**

$K = Rf + \beta (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

| | | [1] | [2] | [3] | [4] | [5] | [6] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Near-term projected 30-year U.S. Treasury bond yield (Q1 2024 - Q1 2025) | Adj. Beta (β) | Market Return (Rm) | Market Risk Premium (Rm − Rf) | CAPM ROE (K) | ECAPM ROE (K) |
| ALLETE, Inc. | ALE | 4.48% | 0.78 | 11.58% | 7.10% | 10.03% | 10.41% |
| Alliant Energy Corporation | LNT | 4.48% | 0.76 | 11.58% | 7.10% | 9.85% | 10.29% |
| Ameren Corporation | AEE | 4.48% | 0.73 | 11.58% | 7.10% | 9.67% | 10.15% |
| American Electric Power Company, Inc. | AEP | 4.48% | 0.73 | 11.58% | 7.10% | 9.69% | 10.17% |
| Avista Corporation | AVA | 4.48% | 0.74 | 11.58% | 7.10% | 9.72% | 10.19% |
| CMS Energy Corporation | CMS | 4.48% | 0.73 | 11.58% | 7.10% | 9.65% | 10.13% |
| Duke Energy Corporation | DUK | 4.48% | 0.71 | 11.58% | 7.10% | 9.50% | 10.02% |
| Entergy Corporation | ETR | 4.48% | 0.80 | 11.58% | 7.10% | 10.18% | 10.53% |
| Evergy, Inc. | EVRG | 4.48% | 0.75 | 11.58% | 7.10% | 9.81% | 10.25% |
| IDACORP, Inc. | IDA | 4.48% | 0.76 | 11.58% | 7.10% | 9.90% | 10.32% |
| NextEra Energy, Inc. | NEE | 4.48% | 0.77 | 11.58% | 7.10% | 9.97% | 10.37% |
| NorthWestern Corporation | NWE | 4.48% | 0.81 | 11.58% | 7.10% | 10.22% | 10.56% |
| OGE Energy Corporation | OGE | 4.48% | 0.84 | 11.58% | 7.10% | 10.45% | 10.73% |
| Pinnacle West Capital Corporation | PNW | 4.48% | 0.78 | 11.58% | 7.10% | 9.99% | 10.39% |
| Portland General Electric Company | POR | 4.48% | 0.76 | 11.58% | 7.10% | 9.86% | 10.29% |
| Southern Company | SO | 4.48% | 0.75 | 11.58% | 7.10% | 9.78% | 10.23% |
| Xcel Energy Inc. | XEL | 4.48% | 0.72 | 11.58% | 7.10% | 9.61% | 10.10% |
| Mean | | | | | | 9.88% | 10.30% |
| Median | | | | | | 9.85% | 10.29% |

Notes:
[1] PAC/407 and AWEC/206
[2] AWEC/206
[3] AWEC/206
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

**CAPITAL ASSET PRICING MODEL**
**PROJECTED RISK FREE RATE AND BETA ADJUSTED TO INDUSTRY**

$K = Rf + \beta (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

| | | [1] | [2] | [3] | [4] | [5] | [6] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Near-term projected 30-year U.S. Treasury bond yield (Q1 2024 - Q1 2025) | Adj. Beta (β) | Market Return (Rm) | Market Risk Premium (Rm − Rf) | CAPM ROE (K) | ECAPM ROE (K) |
| ALLETE, Inc. | ALE | 4.48% | 0.78 | 12.56% | 8.08% | 10.79% | 11.23% |
| Alliant Energy Corporation | LNT | 4.48% | 0.76 | 12.56% | 8.08% | 10.59% | 11.08% |
| Ameren Corporation | AEE | 4.48% | 0.73 | 12.56% | 8.08% | 10.38% | 10.92% |
| American Electric Power Company, Inc. | AEP | 4.48% | 0.73 | 12.56% | 8.08% | 10.41% | 10.95% |
| Avista Corporation | AVA | 4.48% | 0.74 | 12.56% | 8.08% | 10.44% | 10.97% |
| CMS Energy Corporation | CMS | 4.48% | 0.73 | 12.56% | 8.08% | 10.36% | 10.91% |
| Duke Energy Corporation | DUK | 4.48% | 0.71 | 12.56% | 8.08% | 10.19% | 10.78% |
| Entergy Corporation | ETR | 4.48% | 0.80 | 12.56% | 8.08% | 10.97% | 11.36% |
| Evergy, Inc. | EVRG | 4.48% | 0.75 | 12.56% | 8.08% | 10.55% | 11.05% |
| IDACORP, Inc. | IDA | 4.48% | 0.76 | 12.56% | 8.08% | 10.64% | 11.12% |
| NextEra Energy, Inc. | NEE | 4.48% | 0.77 | 12.56% | 8.08% | 10.72% | 11.18% |
| NorthWestern Corporation | NWE | 4.48% | 0.81 | 12.56% | 8.08% | 11.01% | 11.40% |
| OGE Energy Corporation | OGE | 4.48% | 0.84 | 12.56% | 8.08% | 11.27% | 11.59% |
| Pinnacle West Capital Corporation | PNW | 4.48% | 0.78 | 12.56% | 8.08% | 10.75% | 11.20% |
| Portland General Electric Company | POR | 4.48% | 0.76 | 12.56% | 8.08% | 10.59% | 11.08% |
| Southern Company | SO | 4.48% | 0.75 | 12.56% | 8.08% | 10.51% | 11.02% |
| Xcel Energy Inc. | XEL | 4.48% | 0.72 | 12.56% | 8.08% | 10.31% | 10.87% |
| Mean | | | | | | 10.62% | 11.10% |
| Median | | | | | | 10.59% | 11.08% |

Notes:
[1] PAC/407 and AWEC/206
[2] AWEC/206
[3] PAC/407
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

Docket No. UE 433
Exhibit PAC/2221
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**Hamada Adjustment with AWEC's Proposed Capital Structure**

**July 2024**

HAMADA ADJUSTMENT - ADJUSTED MARKET VALUE OF DEBT AND EQUITY & EQUITY RISK PREMIUM
AWEC PROPOSED CAPITALIZATION

| Company | Ticker | Company Proxy Group | Staff Proxy Group | [1] Value Line Cap Structure Percentages (2024) LT Debt | [2] Value Line Cap Structure Percentages (2024) Common Equity | [3] Value Line Cap Structure Percentages (2024) Preferred Stock | [4] Value Line Beta | [5] Value Line 2023 Tax Rate | [6] 2024 Unlevered Beta | [7] 2024 Relevered Beta - Debt at 55.64% | [8] Equity Risk Premium | [9] Hamada 2024 Adjustment - Debt at 55.64% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Alliant Energy Corporation | LNT | Yes | Yes | 40.99 | 59.01 | 0.00 | 0.90 | 2.0% | 0.54 | 1.19 | 4.73% | 1.39% |
| Ameren Corporation | AEE | Yes | Yes | 44.33 | 55.67 | 0.00 | 0.90 | 12.0% | 0.53 | 1.11 | 4.73% | 1.01% |
| American Electric Power Company, Inc. | AEP | Yes | | 49.01 | 50.99 | 0.00 | 0.80 | 21.0% | 0.45 | 0.91 | 4.73% | 0.50% |
| Avista Corporation | AVA | Yes | Yes | 46.30 | 53.70 | 0.00 | 0.90 | 15.0% | 0.52 | 1.07 | 4.73% | 0.82% |
| Black Hills Corporation | BKH | | Yes | 53.47 | 46.53 | 0.00 | 1.00 | 8.5% | 0.49 | 1.05 | 4.73% | 0.22% |
| CMS Energy Corporation | CMS | Yes | | 45.61 | 53.68 | 0.71 | 0.85 | 15.0% | 0.49 | 1.01 | 4.73% | 0.77% |
| Consolidated Edison, Inc. | ED | | Yes | 40.16 | 59.84 | 0.00 | 0.75 | 18.0% | 0.48 | 0.98 | 4.73% | 1.10% |
| Duke Energy Corporation | DUK | Yes | | 48.55 | 50.14 | 1.32 | 0.85 | 9.0% | 0.45 | 0.96 | 4.73% | 0.50% |
| Entergy Corporation | ETR | Yes | | 52.17 | 47.83 | 0.00 | 0.95 | 23.0% | 0.52 | 1.01 | 4.73% | 0.31% |
| Evergy, Inc. | EVRG | Yes | Yes | 50.16 | 49.84 | 0.00 | 0.95 | 9.0% | 0.50 | 1.06 | 4.73% | 0.53% |
| Fortis, Inc. | FTS | | Yes | 49.89 | 47.23 | 2.88 | 0.70 | 14.5% | 0.36 | 0.74 | 4.73% | 0.20% |
| IDACORP, Inc. | IDA | Yes | Yes | 35.04 | 64.96 | 0.00 | 0.85 | 13.0% | 0.58 | 1.21 | 4.73% | 1.70% |
| NextEra Energy, Inc. | NEE | Yes | | 35.92 | 64.08 | 0.00 | 0.95 | 18.0% | 0.65 | 1.32 | 4.73% | 1.75% |
| NorthWestern Corporation | NWE | Yes | Yes | 44.80 | 55.20 | 0.00 | 0.95 | 6.0% | 0.54 | 1.17 | 4.73% | 1.06% |
| OGE Energy Corporation | OGE | Yes | Yes | 39.40 | 60.60 | 0.00 | 1.05 | 12.0% | 0.67 | 1.40 | 4.73% | 1.68% |
| Pinnacle West Capital Corporation | PNW | Yes | Yes | 51.93 | 48.07 | 0.00 | 0.95 | 12.0% | 0.49 | 1.02 | 4.73% | 0.35% |
| Portland General Electric Company | POR | Yes | Yes | 48.46 | 51.54 | 0.00 | 0.90 | 17.5% | 0.51 | 1.03 | 4.73% | 0.62% |
| PPL Corporation | PPL | | Yes | 42.18 | 57.82 | 0.00 | 1.05 | 21.0% | 0.67 | 1.33 | 4.73% | 1.31% |
| Public Service Enterprise Group Inc. | PEG | | Yes | 37.53 | 62.47 | 0.00 | 0.90 | 20.0% | 0.61 | 1.22 | 4.73% | 1.50% |
| Sempra Energy | SRE | | Yes | 38.43 | 60.43 | 1.14 | 1.00 | 19.0% | 0.65 | 1.32 | 4.73% | 1.50% |
| Southern Company | SO | Yes | | 42.85 | 57.15 | 0.00 | 0.90 | 15.0% | 0.55 | 1.14 | 4.73% | 1.12% |
| Wisconsin Energy Corporation | WEC | | Yes | 38.76 | 61.24 | 0.00 | 0.85 | 19.0% | 0.56 | 1.13 | 4.73% | 1.34% |
| Xcel Energy Inc. | XEL | Yes | | 42.31 | 57.69 | 0.00 | 0.85 | 0.0% | 0.49 | 1.11 | 4.73% | 1.21% |
| Company Proxy Group - Mean | | 16 | | 44.87% | 55.01% | 0.13% | | | | | | 0.96% |
| Staff Proxy Group - Mean | | | 16 | 43.86% | 55.88% | 0.25% | | | | | | 1.02% |

Notes
[1] Source: Value Line Reports dated: October 20, 2024, November 10, 2024, and December 8, 2024
[2] Source: Value Line Reports dated: October 20, 2024, November 10, 2024, and December 8, 2024
[3] Equals 100% - [1] - [2]
[4] Source: Value Line Reports dated: April 22, 2022, May 13, 2022, and June 10, 2022
[5] Source: Value Line Reports dated: April 22, 2022, May 13, 2022, and June 10, 2022
[6] Equals [4] / (1 + (1 - [5]) x (([1] + [3]) / [2]))
[7] Equals [6] x (1 + (1 - [5]) x (50.00% / (1 - 50.00%)))
[8] Source: Staff/105 Muldoon/1
[9] Equals [8] x ([7] - [4])

Docket No. UE 433
Exhibit PAC/2222
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Ann E. Bulkley**

**OPUC Response to PacifiCorp Data Request 8**

**July 2024**

| Period | Annualized Price Return | | | Annualized Total Return | | | **Average of Price and Total Returns** | | | Overall |
|---|---|---|---|---|---|---|---|---|---|---|
| | Arithmetic | Arith w/ mo. Comp | Geometric | Arithmetic | Arith w/ mo. Comp | Geometric | Arithmetic | Arith w/ mo. Comp | Geometric | Average |
| 1990-2023 | 8.80% | 9.16% | 7.95% | 10.87% | 11.43% | 10.19% | 9.84% | 10.30% | 9.07% | 9.74% |
| 1993-2023 | 8.88% | 9.25% | 8.03% | 10.83% | 11.38% | 10.14% | 9.85% | 10.31% | **9.08%** | 9.75% |

With Dividend Reinvestment

| Date | Close Px | Dividends | Prc Appr | TR | Pd Appr | Pd Return |
|---|---|---|---|---|---|---|
| 3/29/2024 | 5254.35 | 5.78978 | 4767.84% | 15007.55% | 3.10% | 3.22% |
| 2/29/2024 | 5096.27 | 7.98647 | 4621.39% | 14536.63% | 5.17% | 5.34% |
| 1/31/2024 | 4845.65 | 4.23131 | 4389.21% | 13794.72% | 1.59% | 1.68% |
| 12/29/2023 | 4769.83 | 4.85246 | 4318.96% | 13565.23% | 4.42% | 4.53% |
| 11/30/2023 | 4567.8 | 8.82372 | 4131.80% | 12972.89% | 8.92% | 9.13% |
| 10/31/2023 | 4193.8 | 4.16139 | 3785.31% | 11878.90% | -2.20% | -2.10% |
| 9/29/2023 | 4288.05 | 4.83818 | 3872.62% | 12136.18% | -4.87% | -4.77% |
| 8/31/2023 | 4507.66 | 8.12839 | 4076.08% | 12748.79% | -1.77% | -1.59% |
| 7/31/2023 | 4588.96 | 4.28904 | 4151.40% | 12956.67% | 3.11% | 3.21% |
| 6/30/2023 | 4450.38 | 5.48991 | 4023.01% | 12550.28% | 6.47% | 6.61% |
| 5/31/2023 | 4179.83 | 7.72067 | 3772.36% | 11766.23% | 0.25% | 0.43% |
| 4/28/2023 | 4169.48 | 3.92206 | 3762.78% | 11714.85% | 1.46% | 1.56% |
| 3/31/2023 | 4109.31 | 6.29247 | 3707.03% | 11533.27% | 3.51% | 3.67% |
| 2/28/2023 | 3970.15 | 6.79986 | 3578.11% | 11121.49% | -2.61% | -2.45% |
| 1/31/2023 | 4076.6 | 3.97809 | 3676.73% | 11403.21% | 6.18% | 6.28% |
| 12/30/2022 | 3839.5 | 5.25298 | 3457.07% | 10723.21% | -5.90% | -5.77% |
| 11/30/2022 | 4080.11 | 7.91502 | 3679.98% | 11386.12% | 5.38% | 5.59% |
| 10/31/2022 | 3871.98 | 3.80717 | 3487.16% | 10778.20% | 7.99% | 8.10% |
| 9/30/2022 | 3585.62 | 5.42494 | 3221.86% | 9963.44% | -9.34% | -9.21% |
| 8/31/2022 | 3955 | 7.20541 | 3564.07% | 10984.59% | -4.24% | -4.08% |
| 7/29/2022 | 4130.29 | 3.9233 | 3726.47% | 11455.87% | 9.11% | 9.22% |
| 6/30/2022 | 3785.38 | 5.70104 | 3406.93% | 10480.29% | -8.39% | -8.26% |
| 5/31/2022 | 4132.15 | 7.19003 | 3728.19% | 11432.61% | 0.01% | 0.18% |
| 4/29/2022 | 4131.93 | 3.65935 | 3727.99% | 11411.36% | -8.80% | -8.72% |
| 3/31/2022 | 4530.41 | 5.68487 | 4097.16% | 12511.04% | 3.58% | 3.71% |
| 2/28/2022 | 4373.94 | 6.36784 | 3952.20% | 12059.58% | -3.14% | -3.00% |
| 1/31/2022 | 4515.55 | 4.05651 | 4083.39% | 12435.26% | -5.26% | -5.17% |
| 12/31/2021 | 4766.18 | 5.05513 | 4315.58% | 13119.34% | 4.36% | 4.47% |
| 11/30/2021 | 4567 | 6.50818 | 4131.05% | 12553.13% | -0.83% | -0.70% |
| 10/29/2021 | 4605.38 | 3.77788 | 4166.61% | 12641.69% | 6.91% | 7.01% |
| 9/30/2021 | 4307.54 | 4.88045 | 3890.68% | 11807.55% | -4.76% | -4.65% |
| 8/31/2021 | 4522.68 | 6.12657 | 4089.99% | 12388.57% | 2.90% | 3.04% |
| 7/30/2021 | 4395.26 | 4.28331 | 3971.95% | 12020.04% | 2.27% | 2.38% |
| 6/30/2021 | 4297.5 | 4.67043 | 3881.38% | 11738.83% | 2.22% | 2.33% |
| 5/31/2021 | 4204.11 | 6.18336 | 3794.86% | 11468.79% | 0.55% | 0.70% |
| 4/30/2021 | 4181.17 | 3.69177 | 3773.61% | 11388.58% | 5.24% | 5.34% |
| 3/31/2021 | 3972.89 | 5.04247 | 3580.65% | 10806.52% | 4.24% | 4.38% |
| 2/26/2021 | 3811.15 | 5.62762 | 3430.80% | 10348.99% | 2.61% | 2.76% |
| 1/29/2021 | 3714.24 | 3.66467 | 3341.02% | 10068.58% | -1.11% | -1.02% |
| 12/31/2020 | 3756.07 | 4.59273 | 3379.78% | 10173.14% | 3.71% | 3.84% |
| 11/30/2020 | 3621.63 | 6.16169 | 3255.23% | 9793.11% | 10.75% | 10.95% |
| 10/30/2020 | 3269.96 | 3.75784 | 2929.42% | 8817.03% | -2.77% | -2.66% |
| 9/30/2020 | 3363 | 4.31311 | 3015.62% | 9060.65% | -3.92% | -3.80% |
| 8/31/2020 | 3500.31 | 5.76577 | 3142.83% | 9422.52% | 7.01% | 7.19% |
| 7/31/2020 | 3271.12 | 3.87283 | 2930.50% | 8783.92% | 5.51% | 5.64% |
| 6/30/2020 | 3100.29 | 4.51772 | 2772.24% | 8309.76% | 1.84% | 1.99% |
| 5/29/2020 | 3044.31 | 6.54652 | 2720.37% | 8145.82% | 4.53% | 4.76% |
| 4/30/2020 | 2912.43 | 3.26257 | 2598.19% | 7770.93% | 12.68% | 12.82% |
| 3/31/2020 | 2584.59 | 4.86024 | 2294.47% | 6876.58% | -12.51% | -12.35% |
| 2/28/2020 | 2954.22 | 6.38965 | 2636.91% | 7859.76% | -8.41% | -8.23% |
| 1/31/2020 | 3225.52 | 3.89572 | 2888.25% | 8573.79% | -0.16% | -0.04% |
| 12/31/2019 | 3230.78 | 4.6742 | 2893.13% | 8577.61% | 2.86% | 3.01% |
| 11/29/2019 | 3140.98 | 6.76035 | 2809.93% | 8323.97% | 3.40% | 3.63% |
| 10/31/2019 | 3037.56 | 3.55031 | 2714.12% | 8028.89% | 2.04% | 2.17% |
| 9/30/2019 | 2976.74 | 4.46241 | 2657.77% | 7856.57% | 1.72% | 1.87% |
| 8/30/2019 | 2926.46 | 6.63476 | 2611.19% | 7710.48% | -1.81% | -1.58% |
| 7/31/2019 | 2980.38 | 3.67499 | 2661.15% | 7836.19% | 1.31% | 1.44% |
| 6/28/2019 | 2941.76 | 4.15062 | 2625.37% | 7723.74% | 6.89% | 7.05% |
| 5/31/2019 | 2752.06 | 6.80031 | 2449.62% | 7208.70% | -6.58% | -6.35% |
| 4/30/2019 | 2945.83 | 3.27262 | 2629.14% | 7704.68% | 3.93% | 4.05% |

**pd appr is price appreciation from last period**
**pd return is tr**

**Bloomberg Data Function**

Bloomberg Data (BBG) GO

| | | | | | | |
|---|---|---|---|---|---|---|
| 3/29/2019 | 2834.4 | 4.12131 | 2525.90% | 7400.97% | 1.79% | 1.94% |
| 2/28/2019 | 2784.49 | 6.35421 | 2479.67% | 7258.03% | 2.97% | 3.21% |
| 1/31/2019 | 2704.1 | 3.48807 | 2405.19% | 7029.13% | 7.87% | 8.01% |
| 12/31/2018 | 2506.85 | 4.08824 | 2222.45% | 6500.23% | -9.18% | -9.03% |
| 11/30/2018 | 2760.17 | 6.76685 | 2457.13% | 7155.70% | 1.79% | 2.04% |
| 10/31/2018 | 2711.74 | 3.18704 | 2412.27% | 7010.81% | -6.94% | -6.84% |
| 9/28/2018 | 2913.98 | 4.00961 | 2599.63% | 7532.51% | 0.43% | 0.57% |
| 8/31/2018 | 2901.52 | 6.42007 | 2588.09% | 7489.37% | 3.03% | 3.26% |
| 7/31/2018 | 2816.29 | 3.20148 | 2509.13% | 7249.89% | 3.60% | 3.72% |
| 6/29/2018 | 2718.37 | 3.58419 | 2418.41% | 6986.17% | 0.48% | 0.61% |
| 5/31/2018 | 2705.27 | 6.54317 | 2406.27% | 6942.88% | 2.16% | 2.41% |
| 4/30/2018 | 2648.05 | 2.94757 | 2353.26% | 6777.29% | 0.27% | 0.38% |
| 3/30/2018 | 2640.87 | 4.07626 | 2346.61% | 6751.01% | -2.69% | -2.54% |
| 2/28/2018 | 2713.83 | 5.87011 | 2414.20% | 6929.70% | -3.89% | -3.69% |
| 1/31/2018 | 2823.81 | 2.7602 | 2516.09% | 7198.73% | 5.62% | 5.72% |
| 12/29/2017 | 2673.61 | 3.18199 | 2376.94% | 6803.62% | 0.98% | 1.10% |
| 11/30/2017 | 2647.58 | 6.52918 | 2352.83% | 6728.24% | 2.81% | 3.07% |
| 10/31/2017 | 2575.26 | 2.86208 | 2285.83% | 6525.04% | 2.22% | 2.33% |
| 9/29/2017 | 2519.36 | 3.21738 | 2234.04% | 6373.98% | 1.93% | 2.06% |
| 8/31/2017 | 2471.65 | 6.17013 | 2189.84% | 6243.19% | 0.05% | 0.31% |
| 7/31/2017 | 2470.3 | 2.90212 | 2188.59% | 6223.83% | 1.93% | 2.06% |
| 6/30/2017 | 2423.41 | 3.43432 | 2145.15% | 6096.42% | 0.48% | 0.62% |
| 5/31/2017 | 2411.8 | 5.90387 | 2134.39% | 6058.04% | 1.16% | 1.41% |
| 4/28/2017 | 2384.2 | 2.75519 | 2108.82% | 5972.59% | 0.91% | 1.03% |
| 3/31/2017 | 2362.72 | 3.66481 | 2088.92% | 5910.85% | -0.04% | 0.12% |
| 2/28/2017 | 2363.64 | 5.61968 | 2089.77% | 5903.90% | 3.72% | 3.97% |
| 1/31/2017 | 2278.87 | 2.417 | 2011.24% | 5674.62% | 1.79% | 1.90% |
| 12/30/2016 | 2238.83 | 3.28784 | 1974.14% | 5567.13% | 1.82% | 1.97% |
| 11/30/2016 | 2198.81 | 5.96843 | 1937.07% | 5457.70% | 3.42% | 3.70% |
| 10/31/2016 | 2126.15 | 2.59411 | 1869.75% | 5259.22% | -1.94% | -1.82% |
| 9/30/2016 | 2168.27 | 3.04434 | 1908.77% | 5358.80% | -0.12% | 0.02% |
| 8/31/2016 | 2170.95 | 5.71509 | 1911.26% | 5357.83% | -0.12% | 0.14% |
| 7/29/2016 | 2173.6 | 2.5758 | 1913.71% | 5350.16% | 3.56% | 3.69% |
| 6/30/2016 | 2098.86 | 3.51464 | 1844.47% | 5156.39% | 0.09% | 0.26% |
| 5/31/2016 | 2096.96 | 5.30451 | 1842.71% | 5142.78% | 1.53% | 1.79% |
| 4/29/2016 | 2065.3 | 2.43896 | 1813.38% | 5050.37% | 0.27% | 0.39% |
| 3/31/2016 | 2059.74 | 3.48431 | 1808.23% | 5030.46% | 6.60% | 6.78% |
| 2/29/2016 | 1932.23 | 5.26521 | 1690.10% | 4704.54% | -0.41% | -0.14% |
| 1/29/2016 | 1940.24 | 2.27008 | 1697.52% | 4711.08% | -5.07% | -4.96% |
| 12/31/2015 | 2043.94 | 3.48655 | 1793.59% | 4962.30% | -1.75% | -1.59% |
| 11/30/2015 | 2080.41 | 5.1109 | 1827.38% | 5043.90% | 0.05% | 0.30% |
| 10/30/2015 | 2079.36 | 2.54146 | 1826.40% | 5028.69% | 8.30% | 8.44% |
| 9/30/2015 | 1920.03 | 3.39245 | 1678.79% | 4629.73% | -2.64% | -2.47% |
| 8/31/2015 | 1972.18 | 4.90111 | 1727.11% | 4749.71% | -6.26% | -6.03% |
| 7/31/2015 | 2103.84 | 2.47789 | 1849.08% | 5061.17% | 1.97% | 2.10% |
| 6/30/2015 | 2063.11 | 3.54538 | 1811.35% | 4955.24% | -2.10% | -1.94% |
| 5/29/2015 | 2107.39 | 4.93666 | 1852.37% | 5055.03% | 1.05% | 1.29% |
| 4/30/2015 | 2085.51 | 2.19441 | 1832.10% | 4989.57% | 0.85% | 0.96% |
| 3/31/2015 | 2067.89 | 3.3412 | 1815.78% | 4941.27% | -1.74% | -1.58% |
| 2/27/2015 | 2104.5 | 5.05332 | 1849.69% | 5022.26% | 5.49% | 5.75% |
| 1/30/2015 | 1994.99 | 2.1384 | 1748.24% | 4743.93% | -3.10% | -3.00% |
| 12/31/2014 | 2058.9 | 3.34012 | 1807.45% | 4893.84% | -0.42% | -0.26% |
| 11/28/2014 | 2067.56 | 4.65978 | 1815.47% | 4906.72% | 2.45% | 2.69% |
| 10/31/2014 | 2018.05 | 2.31421 | 1769.60% | 4775.70% | 2.32% | 2.44% |
| 9/30/2014 | 1972.29 | 3.02293 | 1727.21% | 4659.47% | -1.55% | -1.40% |
| 8/29/2014 | 2003.37 | 4.40125 | 1756.00% | 4727.16% | 3.77% | 4.00% |
| 7/31/2014 | 1930.67 | 2.57169 | 1688.65% | 4541.53% | -1.51% | -1.38% |
| 6/30/2014 | 1960.23 | 3.0483 | 1716.04% | 4606.44% | 1.91% | 2.07% |
| 5/30/2014 | 1923.57 | 4.4798 | 1682.07% | 4511.18% | 2.10% | 2.35% |
| 4/30/2014 | 1883.95 | 2.20191 | 1645.37% | 4405.50% | 0.62% | 0.74% |
| 3/31/2014 | 1872.34 | 2.73168 | 1634.61% | 4372.45% | 0.69% | 0.84% |
| 2/28/2014 | 1859.45 | 4.52139 | 1622.67% | 4335.16% | 4.31% | 4.57% |

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|---|---|---|---|---|---|---|
| 1/31/2014 | 1782.59 | 1.90752 | 1551.46% | 4141.22% | -3.56% | -3.46% |
| 12/31/2013 | 1848.36 | 2.97174 | 1612.40% | 4293.11% | 2.36% | 2.52% |
| 11/29/2013 | 1805.81 | 4.17098 | 1572.98% | 4184.93% | 2.80% | 3.05% |
| 10/31/2013 | 1756.54 | 2.22328 | 1527.33% | 4058.27% | 4.46% | 4.60% |
| 9/30/2013 | 1681.55 | 2.63323 | 1457.86% | 3875.54% | 2.97% | 3.14% |
| 8/30/2013 | 1632.97 | 4.00469 | 1412.85% | 3754.65% | -3.13% | -2.90% |
| 7/31/2013 | 1685.73 | 2.24145 | 1461.73% | 3869.70% | 4.95% | 5.09% |
| 6/28/2013 | 1606.28 | 2.57647 | 1388.12% | 3677.48% | -1.50% | -1.34% |
| 5/31/2013 | 1630.74 | 4.18504 | 1410.78% | 3728.89% | 2.08% | 2.34% |
| 4/30/2013 | 1597.57 | 1.81552 | 1380.05% | 3641.45% | 1.81% | 1.93% |
| 3/29/2013 | 1569.19 | 2.27209 | 1353.76% | 3570.73% | 3.60% | 3.75% |
| 2/28/2013 | 1514.68 | 3.75121 | 1303.26% | 3438.04% | 1.11% | 1.36% |
| 1/31/2013 | 1498.11 | 1.91549 | 1287.91% | 3390.67% | 5.04% | 5.18% |
| 12/31/2012 | 1426.19 | 2.81278 | 1221.28% | 3218.79% | 0.71% | 0.91% |
| 11/30/2012 | 1416.18 | 4.07523 | 1212.01% | 3188.98% | 0.28% | 0.58% |
| 10/31/2012 | 1412.16 | 1.87441 | 1208.28% | 3170.05% | -1.98% | -1.85% |
| 9/28/2012 | 1440.67 | 2.24523 | 1234.70% | 3231.56% | 2.42% | 2.58% |
| 8/31/2012 | 1406.58 | 3.80182 | 1203.11% | 3147.65% | 1.98% | 2.25% |
| 7/31/2012 | 1379.32 | 1.73376 | 1177.86% | 3076.08% | 1.26% | 1.39% |
| 6/29/2012 | 1362.16 | 2.09316 | 1161.96% | 3032.59% | 3.96% | 4.12% |
| 5/31/2012 | 1310.33 | 3.64595 | 1113.94% | 2908.62% | -6.27% | -6.01% |
| 4/30/2012 | 1397.91 | 1.70648 | 1195.08% | 3101.00% | -0.75% | -0.63% |
| 3/30/2012 | 1408.47 | 2.03936 | 1204.86% | 3121.23% | 3.13% | 3.29% |
| 2/29/2012 | 1365.68 | 3.44227 | 1165.22% | 3018.77% | 4.06% | 4.32% |
| 1/31/2012 | 1312.41 | 1.53071 | 1115.87% | 2889.50% | 4.36% | 4.48% |
| 12/30/2011 | 1257.61 | 2.05851 | 1065.10% | 2761.28% | 0.85% | 1.02% |
| 11/30/2011 | 1246.96 | 3.51713 | 1055.23% | 2732.36% | -0.51% | -0.22% |
| 10/31/2011 | 1253.3 | 1.66264 | 1061.11% | 2738.66% | 10.77% | 10.93% |
| 9/30/2011 | 1131.42 | 1.85573 | 948.19% | 2458.98% | -7.18% | -7.03% |
| 8/31/2011 | 1218.89 | 3.08882 | 1029.23% | 2652.47% | -5.68% | -5.43% |
| 7/29/2011 | 1292.28 | 1.54063 | 1097.22% | 2810.61% | -2.15% | -2.03% |
| 6/30/2011 | 1320.64 | 2.07917 | 1123.50% | 2871.04% | -1.83% | -1.67% |
| 5/31/2011 | 1345.2 | 2.94963 | 1146.25% | 2921.41% | -1.35% | -1.13% |
| 4/29/2011 | 1363.61 | 1.44351 | 1163.30% | 2956.01% | 2.85% | 2.96% |
| 3/31/2011 | 1325.83 | 1.90216 | 1128.30% | 2868.13% | -0.10% | 0.04% |
| 2/28/2011 | 1327.22 | 2.9342 | 1129.59% | 2866.94% | 3.20% | 3.43% |
| 1/31/2011 | 1286.12 | 1.31607 | 1091.51% | 2768.68% | 2.26% | 2.37% |
| 12/31/2010 | 1257.64 | 1.78858 | 1065.13% | 2702.28% | 6.53% | 6.68% |
| 11/30/2010 | 1180.55 | 2.89445 | 993.71% | 2526.71% | -0.23% | 0.01% |
| 10/29/2010 | 1183.26 | 1.34264 | 996.22% | 2526.40% | 3.69% | 3.80% |
| 9/30/2010 | 1141.2 | 1.73693 | 957.25% | 2430.13% | 8.76% | 8.92% |
| 8/31/2010 | 1049.33 | 2.62787 | 872.14% | 2222.84% | -4.74% | -4.51% |
| 7/30/2010 | 1101.6 | 1.28457 | 920.57% | 2332.67% | 6.88% | 7.01% |
| 6/30/2010 | 1030.71 | 1.7442 | 854.89% | 2173.39% | -5.39% | -5.24% |
| 5/31/2010 | 1089.41 | 2.61966 | 909.27% | 2298.99% | -8.20% | -7.98% |
| 4/30/2010 | 1186.69 | 1.19676 | 999.40% | 2507.17% | 1.48% | 1.58% |
| 3/31/2010 | 1169.43 | 1.68464 | 983.41% | 2466.67% | 5.88% | 6.03% |
| 2/26/2010 | 1104.49 | 2.57872 | 923.24% | 2320.59% | 2.85% | 3.10% |
| 1/29/2010 | 1073.87 | 1.17724 | 894.88% | 2247.91% | -3.70% | -3.60% |
| 12/31/2009 | 1115.1 | 1.68335 | 933.07% | 2335.52% | 1.78% | 1.93% |
| 11/30/2009 | 1095.63 | 2.65999 | 915.04% | 2289.37% | 5.74% | 5.99% |
| 10/30/2009 | 1036.2 | 1.26276 | 859.98% | 2154.25% | -1.98% | -1.86% |
| 9/30/2009 | 1057.08 | 1.59751 | 879.32% | 2196.94% | 3.57% | 3.73% |
| 8/31/2009 | 1020.63 | 2.4417 | 845.55% | 2114.33% | 3.36% | 3.61% |
| 7/31/2009 | 987.48 | 1.27042 | 814.84% | 2037.21% | 7.41% | 7.56% |
| 6/30/2009 | 919.32 | 1.65549 | 751.70% | 1886.93% | 0.02% | 0.20% |
| 5/29/2009 | 919.14 | 2.40503 | 751.53% | 1883.01% | 5.31% | 5.59% |
| 4/30/2009 | 872.81 | 1.34164 | 708.61% | 1778.03% | 9.39% | 9.57% |
| 3/31/2009 | 797.87 | 1.49324 | 639.18% | 1614.01% | 8.54% | 8.76% |
| 2/27/2009 | 735.09 | 3.13522 | 581.02% | 1475.96% | -10.99% | -10.65% |
| 1/30/2009 | 825.88 | 1.32857 | 665.13% | 1663.76% | -8.57% | -8.43% |
| 12/31/2008 | 903.25 | 2.42826 | 736.81% | 1826.10% | 0.78% | 1.06% |

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|---|---|---|---|---|---|---|
| 11/28/2008 | 896.24 | 2.97505 | 730.31% | 1805.85% | -7.48% | -7.17% |
| 10/31/2008 | 968.75 | 1.74421 | 797.49% | 1953.16% | -16.94% | -16.80% |
| 9/30/2008 | 1166.36 | 2.28175 | 980.56% | 2367.60% | -9.08% | -8.91% |
| 8/29/2008 | 1282.83 | 2.8934 | 1088.47% | 2609.01% | 1.22% | 1.45% |
| 7/31/2008 | 1267.38 | 1.85559 | 1074.15% | 2570.38% | -0.99% | -0.84% |
| 6/30/2008 | 1280 | 2.42696 | 1085.84% | 2593.02% | -8.60% | -8.43% |
| 5/30/2008 | 1400.38 | 3.15428 | 1197.37% | 2840.97% | 1.07% | 1.30% |
| 4/30/2008 | 1385.59 | 1.5146 | 1183.67% | 2803.37% | 4.75% | 4.87% |
| 3/31/2008 | 1322.7 | 2.16508 | 1125.40% | 2668.52% | -0.60% | -0.43% |
| 2/29/2008 | 1330.63 | 3.17304 | 1132.75% | 2680.54% | -3.48% | -3.25% |
| 1/31/2008 | 1378.55 | 1.74686 | 1177.15% | 2773.91% | -6.12% | -6.00% |
| 12/31/2007 | 1468.36 | 2.46601 | 1260.35% | 2957.30% | -0.86% | -0.70% |
| 11/30/2007 | 1481.14 | 4.60067 | 1272.19% | 2978.77% | -4.40% | -4.10% |
| 10/31/2007 | 1549.38 | 1.65175 | 1335.41% | 3110.50% | 1.48% | 1.59% |
| 9/28/2007 | 1526.75 | 2.2917 | 1314.44% | 3060.24% | 3.58% | 3.74% |
| 8/31/2007 | 1473.99 | 3.06307 | 1265.56% | 2946.34% | 1.29% | 1.50% |
| 7/31/2007 | 1455.28 | 1.52503 | 1248.23% | 2901.35% | -3.20% | -3.10% |
| 6/29/2007 | 1503.35 | 1.84092 | 1292.76% | 2997.38% | -1.78% | -1.66% |
| 5/31/2007 | 1530.62 | 3.41459 | 1318.03% | 3049.74% | 3.25% | 3.49% |
| 4/30/2007 | 1482.37 | 1.40868 | 1273.33% | 2943.56% | 4.33% | 4.43% |
| 3/30/2007 | 1420.86 | 1.64338 | 1216.34% | 2814.45% | 1.00% | 1.12% |
| 2/28/2007 | 1406.82 | 3.37628 | 1203.34% | 2782.26% | -2.18% | -1.96% |
| 1/31/2007 | 1438.24 | 1.48774 | 1232.44% | 2839.74% | 1.41% | 1.51% |
| 12/29/2006 | 1418.3 | 1.85347 | 1213.97% | 2795.95% | 1.26% | 1.39% |
| 11/30/2006 | 1400.63 | 3.47731 | 1197.60% | 2756.14% | 1.65% | 1.90% |
| 10/31/2006 | 1377.94 | 1.41402 | 1176.58% | 2702.83% | 3.15% | 3.26% |
| 9/29/2006 | 1335.85 | 1.51584 | 1137.59% | 2614.39% | 2.46% | 2.57% |
| 8/31/2006 | 1303.82 | 3.16975 | 1107.91% | 2546.26% | 2.13% | 2.38% |
| 7/31/2006 | 1276.66 | 1.36899 | 1082.75% | 2484.76% | 0.51% | 0.62% |
| 6/30/2006 | 1270.2 | 1.54396 | 1076.77% | 2468.91% | 0.01% | 0.13% |
| 5/31/2006 | 1270.09 | 2.84595 | 1076.66% | 2465.50% | -3.09% | -2.88% |
| 4/28/2006 | 1310.61 | 1.59517 | 1114.20% | 2541.53% | 1.22% | 1.34% |
| 3/31/2006 | 1294.83 | 1.74956 | 1099.58% | 2506.54% | 1.11% | 1.24% |
| 2/28/2006 | 1280.66 | 2.87976 | 1086.46% | 2474.51% | 0.04% | 0.27% |
| 1/31/2006 | 1280.09 | 1.26113 | 1085.93% | 2467.57% | 2.55% | 2.65% |
| 12/30/2005 | 1248.29 | 1.58264 | 1056.47% | 2401.33% | -0.10% | 0.03% |
| 11/30/2005 | 1249.48 | 3.13605 | 1057.57% | 2400.58% | 3.52% | 3.78% |
| 10/31/2005 | 1207.01 | 1.30394 | 1018.22% | 2309.45% | -1.77% | -1.67% |
| 9/30/2005 | 1228.81 | 1.39916 | 1038.42% | 2350.29% | 0.69% | 0.81% |
| 8/31/2005 | 1220.33 | 2.59776 | 1030.56% | 2330.60% | -1.12% | -0.91% |
| 7/29/2005 | 1234.18 | 1.4355 | 1043.39% | 2352.98% | 3.60% | 3.72% |
| 6/30/2005 | 1191.33 | 1.87689 | 1003.70% | 2265.03% | -0.01% | 0.14% |
| 5/31/2005 | 1191.5 | 2.12652 | 1003.85% | 2261.68% | 3.00% | 3.18% |
| 4/29/2005 | 1156.85 | 1.36026 | 971.75% | 2188.85% | -2.01% | -1.90% |
| 3/31/2005 | 1180.59 | 1.71878 | 993.75% | 2233.10% | -1.91% | -1.77% |
| 2/28/2005 | 1203.6 | 2.51539 | 1015.06% | 2275.16% | 1.89% | 2.10% |
| 1/31/2005 | 1181.27 | 1.1096 | 994.38% | 2226.21% | -2.53% | -2.44% |
| 12/31/2004 | 1211.92 | 1.79361 | 1022.77% | 2284.33% | 3.25% | 3.40% |
| 11/30/2004 | 1173.82 | 2.09494 | 987.48% | 2205.92% | 3.86% | 4.05% |
| 10/29/2004 | 1130.2 | 1.40869 | 947.06% | 2116.26% | 1.40% | 1.53% |
| 9/30/2004 | 1114.58 | 1.61169 | 932.59% | 2082.90% | 0.94% | 1.08% |
| 8/31/2004 | 1104.24 | 1.89309 | 923.01% | 2059.52% | 0.23% | 0.40% |
| 7/30/2004 | 1101.72 | 1.36535 | 920.68% | 2050.84% | -3.43% | -3.31% |
| 6/30/2004 | 1140.84 | 1.62533 | 956.92% | 2124.47% | 1.80% | 1.95% |
| 5/31/2004 | 1120.68 | 1.77578 | 938.24% | 2082.03% | 1.21% | 1.37% |
| 4/30/2004 | 1107.31 | 1.25378 | 925.86% | 2052.52% | -1.68% | -1.57% |
| 3/31/2004 | 1126.21 | 1.45728 | 943.37% | 2086.84% | -1.64% | -1.51% |
| 2/27/2004 | 1144.94 | 1.90121 | 960.72% | 2120.34% | 1.22% | 1.39% |
| 1/30/2004 | 1131.13 | 1.19547 | 947.93% | 2089.92% | 1.73% | 1.84% |
| 12/31/2003 | 1111.92 | 1.7225 | 930.13% | 2050.45% | 5.08% | 5.24% |
| 11/28/2003 | 1058.2 | 1.72748 | 880.36% | 1943.31% | 0.71% | 0.88% |
| 10/31/2003 | 1050.71 | 1.53658 | 873.42% | 1925.52% | 5.50% | 5.65% |

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|---|---|---|---|---|---|---|
| 9/30/2003 | 995.97 | 1.36028 | 822.71% | 1817.15% | -1.19% | -1.06% |
| 8/29/2003 | 1008.01 | 1.56905 | 833.86% | 1837.73% | 1.79% | 1.95% |
| 7/31/2003 | 990.31 | 1.3436 | 817.46% | 1800.68% | 1.62% | 1.76% |
| 6/30/2003 | 974.5 | 1.39513 | 802.82% | 1767.81% | 1.13% | 1.27% |
| 5/30/2003 | 963.59 | 1.58925 | 792.71% | 1744.30% | 5.09% | 5.27% |
| 4/30/2003 | 916.92 | 1.07376 | 749.47% | 1652.00% | 8.10% | 8.24% |
| 3/31/2003 | 848.18 | 1.10564 | 685.79% | 1518.70% | 0.84% | 0.97% |
| 2/28/2003 | 841.15 | 1.69239 | 679.28% | 1503.15% | -1.70% | -1.50% |
| 1/31/2003 | 855.7 | 1.11632 | 692.76% | 1527.57% | -2.74% | -2.62% |
| 12/31/2002 | 879.82 | 1.50352 | 715.10% | 1571.36% | -6.03% | -5.88% |
| 11/29/2002 | 936.31 | 1.53438 | 767.44% | 1675.68% | 5.71% | 5.89% |
| 10/31/2002 | 885.76 | 1.20962 | 720.60% | 1576.98% | 8.64% | 8.80% |
| 9/30/2002 | 815.28 | 1.32084 | 655.31% | 1441.31% | -11.00% | -10.87% |
| 8/30/2002 | 916.07 | 1.50333 | 748.68% | 1629.25% | 0.49% | 0.65% |
| 7/31/2002 | 911.62 | 1.06451 | 744.56% | 1618.01% | -7.90% | -7.79% |
| 6/28/2002 | 989.81 | 1.43266 | 817.00% | 1763.24% | -7.25% | -7.12% |
| 5/31/2002 | 1067.14 | 1.87374 | 888.64% | 1905.97% | -0.91% | -0.74% |
| 4/30/2002 | 1076.92 | 0.92048 | 897.70% | 1920.85% | -6.14% | -6.06% |
| 3/29/2002 | 1147.39 | 0.96795 | 962.99% | 2051.32% | 3.67% | 3.76% |
| 2/28/2002 | 1106.73 | 1.65464 | 925.32% | 1973.34% | -2.08% | -1.93% |
| 1/31/2002 | 1130.21 | 1.13538 | 947.07% | 2014.16% | -1.56% | -1.46% |
| 12/31/2001 | 1148.08 | 1.35695 | 963.63% | 2045.45% | 0.76% | 0.88% |
| 11/30/2001 | 1139.45 | 1.61172 | 955.63% | 2026.82% | 7.52% | 7.67% |
| 10/31/2001 | 1059.78 | 1.00508 | 881.82% | 1875.28% | 1.81% | 1.91% |
| 9/28/2001 | 1040.94 | 0.78944 | 864.37% | 1838.35% | -8.17% | -8.08% |
| 8/31/2001 | 1133.58 | 1.90426 | 950.20% | 2008.66% | -6.41% | -6.26% |
| 7/31/2001 | 1211.23 | 1.12011 | 1022.13% | 2149.47% | -1.08% | -0.99% |
| 6/29/2001 | 1224.42 | 0.8377 | 1034.35% | 2171.86% | -2.50% | -2.43% |
| 5/31/2001 | 1255.82 | 2.02103 | 1063.44% | 2228.55% | 0.51% | 0.67% |
| 4/30/2001 | 1249.46 | 0.9582 | 1057.55% | 2213.05% | 7.68% | 7.77% |
| 3/30/2001 | 1160.33 | 1.10365 | 974.98% | 2046.28% | -6.42% | -6.34% |
| 2/28/2001 | 1239.94 | 1.58377 | 1048.73% | 2191.44% | -9.23% | -9.12% |
| 1/31/2001 | 1366.01 | 1.08359 | 1165.53% | 2421.37% | 3.46% | 3.55% |
| 12/29/2000 | 1320.28 | 1.11204 | 1123.16% | 2334.98% | 0.41% | 0.49% |
| 11/30/2000 | 1314.95 | 1.84522 | 1118.22% | 2323.13% | -8.01% | -7.88% |
| 10/31/2000 | 1429.4 | 1.01004 | 1224.25% | 2530.51% | -0.49% | -0.42% |
| 9/29/2000 | 1436.51 | 1.06324 | 1230.84% | 2541.69% | -5.35% | -5.28% |
| 8/31/2000 | 1517.68 | 1.97557 | 1306.04% | 2688.94% | 6.07% | 6.21% |
| 7/31/2000 | 1430.83 | 1.13999 | 1225.58% | 2525.83% | -1.63% | -1.56% |
| 6/30/2000 | 1454.6 | 1.02741 | 1247.60% | 2567.37% | 2.39% | 2.47% |
| 5/31/2000 | 1420.6 | 2.00675 | 1216.10% | 2503.20% | -2.19% | -2.05% |
| 4/28/2000 | 1452.43 | 1.07114 | 1245.59% | 2557.74% | -3.08% | -3.01% |
| 3/31/2000 | 1498.58 | 1.43147 | 1288.35% | 2640.20% | 9.67% | 9.78% |
| 2/29/2000 | 1366.42 | 1.65901 | 1165.91% | 2396.01% | -2.01% | -1.89% |
| 1/31/2000 | 1394.46 | 0.98001 | 1191.88% | 2444.19% | -5.09% | -5.02% |
| 12/31/1999 | 1469.25 | 1.39465 | 1261.17% | 2578.78% | 5.78% | 5.89% |
| 11/30/1999 | 1388.91 | 1.71845 | 1186.74% | 2429.82% | 1.91% | 2.03% |
| 10/29/1999 | 1362.93 | 0.90695 | 1162.67% | 2379.43% | 6.25% | 6.33% |
| 9/30/1999 | 1282.71 | 1.54463 | 1088.36% | 2231.88% | -2.86% | -2.74% |
| 8/31/1999 | 1320.41 | 1.74817 | 1123.28% | 2297.61% | -0.63% | -0.49% |
| 7/30/1999 | 1328.72 | 1.15577 | 1130.98% | 2309.50% | -3.20% | -3.12% |
| 6/30/1999 | 1372.71 | 1.32058 | 1171.73% | 2387.19% | 5.44% | 5.55% |
| 5/31/1999 | 1301.84 | 1.85175 | 1106.08% | 2256.42% | -2.50% | -2.36% |
| 4/30/1999 | 1335.18 | 0.99365 | 1136.97% | 2313.41% | 3.79% | 3.87% |
| 3/31/1999 | 1286.37 | 1.4898 | 1091.75% | 2223.45% | 3.88% | 4.00% |
| 2/26/1999 | 1238.33 | 1.53665 | 1047.24% | 2134.07% | -3.23% | -3.11% |
| 1/29/1999 | 1279.64 | 0.9729 | 1085.51% | 2205.75% | 4.10% | 4.18% |
| 12/31/1998 | 1229.23 | 1.38571 | 1038.81% | 2113.20% | 5.64% | 5.76% |
| 11/30/1998 | 1163.63 | 1.59846 | 978.03% | 1992.66% | 5.91% | 6.06% |
| 10/30/1998 | 1098.67 | 0.98032 | 917.85% | 1873.08% | 8.03% | 8.13% |
| 9/30/1998 | 1017.01 | 1.60072 | 842.20% | 1724.68% | 6.24% | 6.41% |
| 8/31/1998 | 957.28 | 1.52464 | 786.86% | 1614.82% | -14.58% | -14.46% |

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|---|---|---|---|---|---|---|
| 7/31/1998 | 1120.67 | 1.11406 | 938.23% | 1904.66% | -1.16% | -1.07% |
| 6/30/1998 | 1133.84 | 1.24616 | 950.44% | 1926.26% | 3.94% | 4.06% |
| 5/29/1998 | 1090.82 | 1.81223 | 910.58% | 1847.18% | -1.88% | -1.72% |
| 4/30/1998 | 1111.75 | 1.05286 | 929.97% | 1881.30% | 0.91% | 1.00% |
| 3/31/1998 | 1101.75 | 1.27402 | 920.71% | 1861.61% | 4.99% | 5.12% |
| 2/27/1998 | 1049.34 | 1.60004 | 872.15% | 1766.06% | 7.04% | 7.21% |
| 1/30/1998 | 980.28 | 0.86215 | 808.17% | 1640.53% | 1.02% | 1.11% |
| 12/31/1997 | 970.43 | 1.34527 | 799.05% | 1621.51% | 1.57% | 1.72% |
| 11/28/1997 | 955.4 | 1.53092 | 785.12% | 1592.48% | 4.46% | 4.63% |
| 10/31/1997 | 914.62 | 1.04977 | 747.34% | 1517.59% | -3.45% | -3.34% |
| 9/30/1997 | 947.28 | 1.42149 | 777.60% | 1573.49% | 5.32% | 5.48% |
| 8/29/1997 | 899.47 | 1.37038 | 733.31% | 1486.60% | -5.74% | -5.61% |
| 7/31/1997 | 954.29 | 1.19788 | 784.09% | 1580.82% | 7.81% | 7.95% |
| 6/30/1997 | 885.14 | 1.12303 | 720.03% | 1457.00% | 4.35% | 4.48% |
| 5/30/1997 | 848.28 | 1.80875 | 685.88% | 1390.24% | 5.86% | 6.09% |
| 4/30/1997 | 801.34 | 0.9179 | 642.39% | 1304.72% | 5.84% | 5.97% |
| 3/31/1997 | 757.12 | 1.26953 | 601.43% | 1225.62% | -4.26% | -4.11% |
| 2/28/1997 | 790.82 | 1.51233 | 632.65% | 1282.41% | 0.59% | 0.78% |
| 1/31/1997 | 786.16 | 0.81991 | 628.33% | 1271.66% | 6.13% | 6.25% |
| 12/31/1996 | 740.74 | 1.26957 | 586.25% | 1191.03% | -2.15% | -1.98% |
| 11/29/1996 | 757.02 | 1.50885 | 601.33% | 1217.15% | 7.34% | 7.56% |
| 10/31/1996 | 705.27 | 0.97734 | 553.39% | 1124.60% | 2.61% | 2.76% |
| 9/30/1996 | 687.31 | 1.34515 | 536.75% | 1091.75% | 5.42% | 5.63% |
| 8/30/1996 | 651.99 | 1.48102 | 504.03% | 1028.24% | 1.88% | 2.11% |
| 7/31/1996 | 639.95 | 1.05162 | 492.88% | 1004.93% | -4.57% | -4.42% |
| 6/28/1996 | 670.63 | 1.02969 | 521.30% | 1056.03% | 0.23% | 0.38% |
| 5/31/1996 | 669.12 | 1.84727 | 519.90% | 1051.66% | 2.29% | 2.57% |
| 4/30/1996 | 654.17 | 0.81661 | 506.05% | 1022.78% | 1.34% | 1.47% |
| 3/29/1996 | 645.5 | 1.09529 | 498.02% | 1006.50% | 0.79% | 0.96% |
| 2/29/1996 | 640.43 | 1.4995 | 493.32% | 995.96% | 0.69% | 0.93% |
| 1/31/1996 | 636.02 | 0.81118 | 489.24% | 985.90% | 3.26% | 3.40% |
| 12/29/1995 | 615.93 | 1.07614 | 470.62% | 950.22% | 1.74% | 1.92% |
| 11/30/1995 | 605.37 | 1.61376 | 460.84% | 930.42% | 4.10% | 4.39% |
| 10/31/1995 | 581.5 | 0.81601 | 438.73% | 887.11% | -0.50% | -0.36% |
| 9/29/1995 | 584.41 | 1.17046 | 441.42% | 890.66% | 4.01% | 4.22% |
| 8/31/1995 | 561.88 | 1.56625 | 420.55% | 850.54% | -0.03% | 0.25% |
| 7/31/1995 | 562.06 | 0.7457 | 420.72% | 848.19% | 3.18% | 3.32% |
| 6/30/1995 | 544.75 | 1.02542 | 404.68% | 817.75% | 2.13% | 2.32% |
| 5/31/1995 | 533.4 | 1.83087 | 394.16% | 796.93% | 3.63% | 3.99% |
| 4/28/1995 | 514.71 | 0.7327 | 376.85% | 762.47% | 2.80% | 2.94% |
| 3/31/1995 | 500.71 | 1.03626 | 363.88% | 737.80% | 2.73% | 2.95% |
| 2/28/1995 | 487.39 | 1.34523 | 351.54% | 713.79% | 3.61% | 3.90% |
| 1/31/1995 | 470.42 | 0.75135 | 335.82% | 683.27% | 2.43% | 2.59% |
| 12/30/1994 | 459.27 | 1.11396 | 325.49% | 663.47% | 1.23% | 1.48% |
| 11/30/1994 | 453.69 | 1.48114 | 320.32% | 652.35% | -3.95% | -3.64% |
| 10/31/1994 | 472.35 | 0.72087 | 337.60% | 680.78% | 2.09% | 2.25% |
| 9/30/1994 | 462.69 | 1.17069 | 328.66% | 663.63% | -2.69% | -2.45% |
| 8/31/1994 | 475.49 | 1.51487 | 340.51% | 682.79% | 3.76% | 4.10% |
| 7/29/1994 | 458.26 | 0.57327 | 324.55% | 651.96% | 3.15% | 3.28% |
| 6/30/1994 | 444.27 | 1.06793 | 311.59% | 628.07% | -2.68% | -2.45% |
| 5/31/1994 | 456.5 | 1.78248 | 322.92% | 646.35% | 1.24% | 1.64% |
| 4/29/1994 | 450.91 | 0.57033 | 317.74% | 634.30% | 1.15% | 1.28% |
| 3/31/1994 | 445.77 | 1.05033 | 312.98% | 625.01% | -4.57% | -4.36% |
| 2/28/1994 | 467.14 | 1.40932 | 332.78% | 658.04% | -3.00% | -2.71% |
| 1/31/1994 | 481.61 | 0.68573 | 346.18% | 679.19% | 3.25% | 3.40% |
| 12/31/1993 | 466.45 | 0.91213 | 332.14% | 653.57% | 1.01% | 1.21% |
| 11/30/1993 | 461.79 | 1.57952 | 327.82% | 644.58% | -1.29% | -0.95% |
| 10/29/1993 | 467.83 | 0.5871 | 333.42% | 651.75% | 1.94% | 2.07% |
| 9/30/1993 | 458.93 | 1.05713 | 325.17% | 636.52% | -1.00% | -0.77% |
| 8/31/1993 | 463.56 | 1.52765 | 329.46% | 642.24% | 3.44% | 3.79% |
| 7/30/1993 | 448.13 | 0.58794 | 315.17% | 615.12% | -0.53% | -0.40% |
| 6/30/1993 | 450.53 | 0.96592 | 317.39% | 618.00% | 0.08% | 0.29% |

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|---|---|---|---|---|---|---|
| 5/31/1993 | 450.19 | 1.73462 | 317.07% | 615.92% | 2.27% | 2.67% |
| 4/30/1993 | 440.19 | 0.56216 | 307.81% | 597.28% | -2.54% | -2.42% |
| 3/31/1993 | 451.67 | 1.06448 | 318.45% | 614.56% | 1.87% | 2.11% |
| 2/26/1993 | 443.38 | 1.37486 | 310.77% | 599.78% | 1.05% | 1.36% |
| 1/29/1993 | 438.78 | 0.56896 | 306.50% | 590.38% | 0.70% | 0.84% |
| 12/31/1992 | 435.71 | 0.92493 | 303.66% | 584.65% | 1.01% | 1.23% |
| 11/30/1992 | 431.35 | 1.54387 | 299.62% | 576.36% | 3.03% | 3.40% |
| 10/30/1992 | 418.68 | 0.55247 | 287.88% | 554.10% | 0.21% | 0.35% |
| 9/30/1992 | 417.8 | 1.09846 | 287.07% | 551.85% | 0.91% | 1.18% |
| 8/31/1992 | 414.03 | 1.51092 | 283.57% | 544.28% | -2.40% | -2.05% |
| 7/31/1992 | 424.21 | 0.58973 | 293.01% | 557.74% | 3.94% | 4.09% |
| 6/30/1992 | 408.14 | 1.03347 | 278.12% | 531.93% | -1.74% | -1.49% |
| 5/29/1992 | 415.35 | 1.65991 | 284.80% | 541.47% | 0.10% | 0.50% |
| 4/30/1992 | 414.95 | 0.5774 | 284.43% | 538.29% | 2.79% | 2.94% |
| 3/31/1992 | 403.69 | 0.9906 | 274.00% | 520.09% | -2.18% | -1.95% |
| 2/28/1992 | 412.7 | 1.37703 | 282.34% | 532.39% | 0.96% | 1.29% |
| 1/31/1992 | 408.79 | 0.53825 | 278.72% | 524.31% | -1.99% | -1.86% |
| 12/31/1991 | 417.09 | 0.95213 | 286.41% | 536.17% | 11.16% | 11.43% |
| 11/29/1991 | 375.22 | 1.45141 | 247.62% | 470.91% | -4.39% | -4.03% |
| 10/31/1991 | 392.46 | 0.59871 | 263.59% | 494.90% | 1.19% | 1.34% |
| 9/30/1991 | 387.86 | 0.95019 | 259.33% | 487.02% | -1.91% | -1.67% |
| 8/30/1991 | 395.43 | 1.49549 | 266.34% | 497.01% | 1.96% | 2.36% |
| 7/31/1991 | 387.81 | 0.62644 | 259.28% | 483.26% | 4.49% | 4.66% |
| 6/28/1991 | 371.16 | 0.8203 | 243.86% | 457.30% | -4.79% | -4.58% |
| 5/31/1991 | 389.83 | 1.65574 | 261.15% | 484.06% | 3.86% | 4.31% |
| 4/30/1991 | 375.35 | 0.73954 | 247.74% | 459.91% | 0.03% | 0.23% |
| 3/29/1991 | 375.22 | 0.73898 | 247.62% | 458.62% | 2.22% | 2.42% |
| 2/28/1991 | 367.07 | 1.39651 | 240.07% | 445.40% | 6.73% | 7.14% |
| 1/31/1991 | 343.93 | 0.6181 | 218.63% | 409.04% | 4.15% | 4.35% |
| 12/31/1990 | 330.22 | 0.95031 | 205.93% | 387.82% | 2.48% | 2.78% |
| 11/30/1990 | 322.22 | 1.37085 | 198.52% | 374.62% | 5.99% | 6.46% |
| 10/31/1990 | 304 | 0.74605 | 181.64% | 345.84% | -0.67% | -0.43% |
| 9/28/1990 | 306.05 | 0.81547 | 183.54% | 347.76% | -5.12% | -4.87% |
| 8/31/1990 | 322.56 | 1.41167 | 198.83% | 370.69% | -9.43% | -9.05% |
| 7/31/1990 | 356.15 | 0.71317 | 229.95% | 417.51% | -0.52% | -0.32% |
| 6/29/1990 | 358.02 | 0.76562 | 231.68% | 419.19% | -0.89% | -0.68% |
| 5/31/1990 | 361.23 | 1.72836 | 234.66% | 422.73% | 9.20% | 9.74% |
| 4/30/1990 | 330.8 | 0.6471 | 206.47% | 376.33% | -2.69% | -2.50% |
| 3/30/1990 | 339.94 | 0.7229 | 214.93% | 388.55% | 2.43% | 2.65% |
| 2/28/1990 | 331.89 | 1.40155 | 207.48% | 375.96% | 0.85% | 1.28% |
| 1/31/1990 | 329.08 | 0.60773 | 204.87% | 369.94% | -6.88% | -6.71% |
| 12/29/1989 | 353.4 | 0.887 | 227.40% | 403.76% | 2.14% | 2.40% |
| 11/30/1989 | 345.99 | 1.283 | 220.54% | 391.95% | 1.65% | 2.04% |
| 10/31/1989 | 340.36 | 0.693 | 215.32% | 382.11% | -2.52% | -2.32% |
| 9/29/1989 | 349.15 | 0.869 | 223.47% | 393.57% | -0.65% | -0.41% |
| 8/31/1989 | 351.45 | 1.373 | 225.60% | 395.58% | 1.55% | 1.95% |
| 7/31/1989 | 346.08 | 0.585 | 220.62% | 386.08% | 8.84% | 9.03% |
| 6/30/1989 | 317.98 | 0.736 | 194.59% | 345.83% | -0.79% | -0.57% |
| 5/31/1989 | 320.52 | 1.601 | 196.94% | 348.37% | 3.51% | 4.05% |
| 4/28/1989 | 309.64 | 0.524 | 186.86% | 330.94% | 5.01% | 5.19% |
| 3/31/1989 | 294.87 | 0.721 | 173.18% | 309.67% | 2.08% | 2.33% |
| 2/28/1989 | 288.86 | 1.216 | 167.61% | 300.33% | -2.89% | -2.49% |
| 1/31/1989 | 297.47 | 0.53 | 175.59% | 310.56% | 7.11% | 7.31% |
| 12/30/1988 | 277.72 | 0.751 | 157.29% | 282.59% | 1.47% | 1.74% |
| 11/30/1988 | 273.7 | 1.285 | 153.57% | 276.03% | -1.89% | -1.43% |
| 10/31/1988 | 278.97 | 0.506 | 158.45% | 281.47% | 2.60% | 2.78% |
| 9/30/1988 | 271.91 | 0.74 | 151.91% | 271.14% | 3.97% | 4.26% |
| 8/31/1988 | 261.52 | 1.278 | 142.28% | 255.97% | -3.86% | -3.40% |
| 7/29/1988 | 272.02 | 0.438 | 152.01% | 268.49% | -0.54% | -0.38% |
| 6/30/1988 | 273.5 | 0.682 | 153.38% | 269.89% | 4.33% | 4.59% |
| 5/31/1988 | 262.16 | 1.399 | 142.88% | 253.66% | 0.32% | 0.86% |
| 4/29/1988 | 261.33 | 0.423 | 142.11% | 250.63% | 0.94% | 1.11% |

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|---|---|---|---|---|---|---|
| 3/31/1988 | 258.89 | 0.669 | 139.85% | 246.79% | -3.33% | -3.09% |
| 2/29/1988 | 267.82 | 1.179 | 148.12% | 257.85% | 4.18% | 4.66% |
| 1/29/1988 | 257.07 | 0.395 | 138.16% | 241.91% | 4.04% | 4.21% |
| 12/31/1987 | 247.08 | 0.74 | 128.91% | 228.11% | 7.29% | 7.61% |
| 11/30/1987 | 230.3 | 0.74 | 113.36% | 204.91% | -8.53% | -8.24% |
| 10/30/1987 | 251.79 | 0.73 | 133.27% | 232.30% | -21.76% | -21.54% |
| 9/30/1987 | 321.83 | 0.74 | 198.16% | 323.50% | -2.42% | -2.19% |
| 8/31/1987 | 329.8 | 0.75 | 205.54% | 332.99% | 3.50% | 3.73% |
| 7/31/1987 | 318.66 | 0.74 | 195.22% | 317.42% | 4.82% | 5.07% |
| 6/30/1987 | 304 | 0.75 | 181.64% | 297.29% | 4.79% | 5.05% |
| 5/29/1987 | 290.1 | 0.76 | 168.76% | 278.19% | 0.60% | 0.87% |
| 4/30/1987 | 288.36 | 0.75 | 167.15% | 274.94% | -1.15% | -0.89% |
| 3/31/1987 | 291.7 | 0.7 | 170.24% | 278.30% | 2.64% | 2.89% |
| 2/27/1987 | 284.2 | 0.71 | 163.29% | 267.69% | 3.69% | 3.95% |
| 1/30/1987 | 274.08 | 0.7 | 153.92% | 253.72% | 13.18% | 13.47% |
| 12/31/1986 | 242.17 | 0.69 | 124.36% | 211.74% | -2.83% | -2.55% |
| 11/28/1986 | 249.22 | 0.69 | 130.89% | 219.90% | 2.15% | 2.43% |
| 10/31/1986 | 243.98 | 0.68 | 126.03% | 212.31% | 5.47% | 5.77% |
| 9/30/1986 | 231.32 | 0.7 | 114.30% | 195.28% | -8.54% | -8.27% |
| 8/29/1986 | 252.93 | 0.7 | 134.33% | 221.89% | 7.12% | 7.42% |
| 7/31/1986 | 236.12 | 0.69 | 118.75% | 199.67% | -5.87% | -5.59% |
| 6/30/1986 | 250.84 | 0.69 | 132.39% | 217.43% | 1.41% | 1.69% |
| 5/30/1986 | 247.35 | 0.7 | 129.16% | 212.15% | 5.02% | 5.32% |
| 4/30/1986 | 235.52 | 0.69 | 118.20% | 196.38% | -1.41% | -1.13% |
| 3/31/1986 | 238.9 | 0.68 | 121.33% | 199.76% | 5.28% | 5.58% |
| 2/28/1986 | 226.92 | 0.69 | 110.23% | 183.92% | 7.15% | 7.47% |
| 1/31/1986 | 211.78 | 0.68 | 96.20% | 164.17% | 0.24% | 0.56% |
| 12/31/1985 | 211.28 | 0.67 | 95.74% | 162.70% | 4.51% | 4.84% |
| 11/29/1985 | 202.17 | 0.67 | 87.30% | 150.58% | 6.51% | 6.86% |
| 10/31/1985 | 189.82 | 0.67 | 75.86% | 134.50% | 4.25% | 4.62% |
| 9/30/1985 | 182.08 | 0.65 | 68.69% | 124.15% | -3.47% | -3.13% |
| 8/30/1985 | 188.63 | 0.65 | 74.75% | 131.38% | -1.20% | -0.86% |
| 7/31/1985 | 190.92 | 0.65 | 76.88% | 133.39% | -0.48% | -0.15% |
| 6/28/1985 | 191.85 | 0.67 | 77.74% | 133.73% | 1.21% | 1.57% |
| 5/31/1985 | 189.55 | 0.67 | 75.61% | 130.12% | 5.41% | 5.78% |
| 4/30/1985 | 179.83 | 0.66 | 66.60% | 117.55% | -0.46% | -0.09% |
| 3/29/1985 | 180.66 | 0.64 | 67.37% | 117.76% | -0.29% | 0.07% |
| 2/28/1985 | 181.18 | 0.65 | 67.85% | 117.61% | 0.86% | 1.22% |
| 1/31/1985 | 179.63 | 0.64 | 66.42% | 114.98% | 7.41% | 7.79% |
| 12/31/1984 | 167.24 | 0.65 | 54.94% | 99.44% | 2.24% | 2.63% |
| 11/30/1984 | 163.58 | 0.65 | 51.55% | 94.32% | -1.51% | -1.12% |
| 10/31/1984 | 166.09 | 0.65 | 53.87% | 96.52% | -0.01% | 0.39% |
| 9/28/1984 | 166.1 | 0.62 | 53.88% | 95.77% | -0.35% | 0.02% |
| 8/31/1984 | 166.68 | 0.62 | 54.42% | 95.72% | 10.63% | 11.04% |
| 7/31/1984 | 150.66 | 0.62 | 39.58% | 76.25% | -1.65% | -1.24% |
| 6/29/1984 | 153.18 | 0.64 | 41.91% | 78.47% | 1.75% | 2.17% |
| 5/31/1984 | 150.55 | 0.64 | 39.48% | 74.67% | -5.94% | -5.54% |
| 4/30/1984 | 160.05 | 0.64 | 48.28% | 84.91% | 0.55% | 0.95% |
| 3/30/1984 | 159.18 | 0.6 | 47.47% | 83.17% | 1.35% | 1.73% |
| 2/29/1984 | 157.06 | 0.6 | 45.51% | 80.05% | -3.89% | -3.52% |
| 1/31/1984 | 163.41 | 0.6 | 51.39% | 86.62% | -0.92% | -0.56% |
| 12/30/1983 | 164.93 | 0.6 | 52.80% | 87.67% | -0.88% | -0.52% |
| 11/30/1983 | 166.4 | 0.6 | 54.16% | 88.65% | 1.74% | 2.11% |
| 10/31/1983 | 163.55 | 0.6 | 51.52% | 84.76% | -1.52% | -1.16% |
| 9/30/1983 | 166.07 | 0.6 | 53.85% | 86.92% | 1.02% | 1.38% |
| 8/31/1983 | 164.4 | 0.6 | 52.31% | 84.37% | 1.13% | 1.50% |
| 7/29/1983 | 162.56 | 0.59 | 50.60% | 81.65% | -3.30% | -2.95% |
| 6/30/1983 | 168.11 | 0.6 | 55.74% | 87.17% | 3.52% | 3.89% |
| 5/31/1983 | 162.39 | 0.6 | 50.45% | 80.16% | -1.23% | -0.87% |
| 4/29/1983 | 164.42 | 0.59 | 52.33% | 81.74% | 7.49% | 7.88% |
| 3/31/1983 | 152.96 | 0.57 | 41.71% | 68.47% | 3.31% | 3.69% |
| 2/28/1983 | 148.06 | 0.57 | 37.17% | 62.46% | 1.90% | 2.29% |

| | | | | | | |
|---|---|---|---|---|---|---|
| 1/31/1983 | 145.3 | 0.57 | 34.61% | 58.82% | 3.31% | 3.72% |
| 12/31/1982 | 140.64 | 0.57 | 30.30% | 53.13% | 1.52% | 1.93% |
| 11/30/1982 | 138.54 | 0.57 | 28.35% | 50.23% | 3.61% | 4.04% |
| 10/29/1982 | 133.71 | 0.57 | 23.87% | 44.40% | 11.04% | 11.51% |
| 9/30/1982 | 120.42 | 0.58 | 11.56% | 29.50% | 0.76% | 1.25% |
| 8/31/1982 | 119.51 | 0.58 | 10.72% | 27.90% | 11.60% | 12.14% |
| 7/30/1982 | 107.09 | 0.57 | -0.79% | 14.06% | -2.30% | -1.78% |
| 6/30/1982 | 109.61 | 0.59 | 1.55% | 16.12% | -2.03% | -0.98% |
| 5/31/1982 | 111.88 | -- | 3.65% | 17.27% | -3.92% | -3.92% |
| 4/30/1982 | 116.44 | 0.58 | 7.88% | 22.05% | 4.00% | 4.52% |
| 3/31/1982 | 111.96 | 0.56 | 3.72% | 16.77% | -1.02% | -0.52% |
| 2/26/1982 | 113.11 | 0.56 | 4.79% | 17.39% | -6.05% | -5.59% |
| 1/29/1982 | 120.4 | 0.55 | 11.54% | 24.34% | -1.75% | -1.31% |
| 12/31/1981 | 122.55 | 0.56 | 13.54% | 25.98% | -3.01% | -2.56% |
| 11/30/1981 | 126.35 | 0.57 | 17.06% | 29.30% | 3.66% | 4.13% |
| 10/30/1981 | 121.89 | 0.56 | 12.92% | 24.17% | 4.91% | 5.40% |
| 9/30/1981 | 116.18 | 0.56 | 7.63% | 17.81% | -5.38% | -4.93% |
| 8/31/1981 | 122.79 | 0.57 | 13.76% | 23.92% | -6.21% | -5.77% |
| 7/31/1981 | 130.92 | 0.56 | 21.29% | 31.51% | -0.22% | 0.21% |
| 6/30/1981 | 131.21 | 0.55 | 21.56% | 31.24% | -1.04% | -0.63% |
| 5/29/1981 | 132.59 | 0.56 | 22.84% | 32.07% | -0.17% | 0.26% |
| 4/30/1981 | 132.81 | 0.56 | 23.04% | 31.73% | -2.35% | -1.93% |
| 3/31/1981 | 136 | 0.52 | 26.00% | 34.33% | 3.60% | 4.00% |
| 2/27/1981 | 131.27 | 0.53 | 21.61% | 29.17% | 1.33% | 1.74% |
| 1/30/1981 | 129.55 | 0.53 | 20.02% | 26.96% | -4.57% | -4.18% |
| 12/31/1980 | 135.76 | 0.52 | 25.77% | 32.50% | -3.39% | -3.02% |
| 11/28/1980 | 140.52 | 0.53 | 30.18% | 36.63% | 10.24% | 10.65% |
| 10/31/1980 | 127.47 | 0.53 | 18.09% | 23.47% | 1.60% | 2.02% |
| 9/30/1980 | 125.46 | 0.52 | 16.23% | 21.02% | 2.52% | 2.94% |
| 8/29/1980 | 122.38 | 0.52 | 13.38% | 17.56% | 0.58% | 1.01% |
| 7/31/1980 | 121.67 | 0.52 | 12.72% | 16.39% | 6.50% | 6.96% |
| 6/30/1980 | 114.24 | 0.52 | 5.84% | 8.82% | 2.70% | 3.16% |
| 5/30/1980 | 111.24 | 0.52 | 3.06% | 5.48% | 4.66% | 5.15% |
| 4/30/1980 | 106.29 | 0.52 | -1.53% | 0.32% | 4.11% | 4.62% |
| 3/31/1980 | 102.09 | 0.52 | -5.42% | -4.12% | -10.18% | -9.72% |
| 2/29/1980 | 113.66 | 0.49 | 5.30% | 6.21% | -0.44% | -0.01% |
| 1/31/1980 | 114.16 | 0.49 | 5.76% | 6.22% | 5.76% | 6.22% |
| 12/31/1979 | 107.94 | -- | 0.00% | 0.00% | -- | 2.14% |

Docket No. UE 433
Exhibit PAC/2300
Witness: Joelle R. Steward

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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# Reply Testimony of Joelle R. Steward

**July 2024**

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**Q. Are you the same Joelle R. Steward who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?**

A. Yes.

## I. PURPOSE AND SUMMARY

**Q. What is the purpose of your testimony in this proceeding?**

A. My testimony responds to the opening testimony of Nicola Peterson, Rose Pileggi, Bret Stevens, and April Brewer filed on behalf of the Public Utility Commission of Oregon (Commission) Staff (Staff); Bob Jenks, filed on behalf of the Oregon Citizens' Utility Board (CUB); and Chad D. Wilcox, filed on behalf of the Alliance of Western Energy Consumers (AWEC). I also discuss the Company's withdrawal of its proposed Catastrophic Fire Fund (CFF) from this proceeding in favor of a future docket focused specifically on CFF issues.

**Q. Please summarize your testimony.**

A. Testimony filed on behalf of Staff, CUB, and AWEC included responses to the Company's proposals in my direct testimony that address the increasing risk of wildfire liability and its impact on the financial health of the Company. The parties' responses indicate consensus on three facts underlying PacifiCorp's proposals for establishing an Insurance Cost Adjustment (ICA) to facilitate an insurance mechanism and a CFF:

- The cost of commercial insurance to cover the Company's risk of wildfire liability is rising, and the available coverage options are shrinking.

- The status quo is unsustainable. As CUB's testimony recognizes, "there needs to be some kind of mechanism to mitigate these rising costs."[1]

- The Company's use of commercial insurance, increased self-insurance, and creation of a CFF should be driven by which approach offers the most economically efficient use of the funds dedicated to insuring against unplanned events.

These are among the central principles underlying the Company's wildfire insurance proposals. As most of the witnesses recognize, the question is not "whether" wildfire liability insurance issues demand a new approach to meet current circumstances, but "how" that approach should be constructed. The Company acknowledges the objections that various parties have to the "how" when it comes to the implementation of the Company's wildfire insurance proposals.

Beginning with the ICA, as noted in my direct testimony, PacifiCorp is *not* asking the Commission to approve the details of an insurance mechanism necessary to realize a self-insurance program in this case. Rather, the ICA seeks only to separately account for wildfire insurance expenses in base rates to facilitate a future transition to an optimum mix of commercial policies and self-insurance without prejudging how an insurance mechanism would operate. The expense items the Company proposes to include in the ICA are forecast insurance costs for the 2024-2025 insurance year, as described in the reply testimony of Company witness Mariya V. Coleman, and amortization of the insurance deferral approved in docket UM 2301.[2] Thus, approval of the ICA rider in this case simply allows inclusion of the Company's insurance expense for the test year in revenue requirement, consistent

[1] CUB/100, Jenks/68.
[2] *In the Matter of PacifiCorp, dba Pacific Power, Application for Authorization of Deferred Accounting Related to Insurance Costs*, Docket No. UM 2301, Order No. 24-021 (Jan. 24, 2024).

with past cases, and recovery of the UM 2301 deferral (which would cease at the end of the three-year amortization schedule). The Company still intends to make a separate filing for an insurance mechanism once the parameters of that mechanism are more fully developed through ongoing stakeholder workshops and additional analysis.

As for the CFF, the Company always contemplated further process would be necessary to establish the multi-state CFF, but proposed an order in this proceeding authorizing a surcharge that would provide funding for the ultimate vehicle that achieves the goals of the CFF.[3] PacifiCorp now believes that the best means of moving a CFF proposal forward is to withdraw it from further consideration in this proceeding and initiate a separate future docket to take up CFF issues. A separate proceeding will enable the Company and parties to focus on resolving the questions about a CFF raised in testimony and, more broadly, catastrophic liability risks. Additionally, since the Company's direct filing in February, Utah passed a new law, Senate Bill 224 (SB 224), which requires a thoughtful reconsideration of the allocation and operation of any multi-state CFF.[4]

In this proceeding, and in multi-state stakeholder discussions, PacifiCorp is seeking a path forward on wildfire liability issues that all stakeholders agree present new and critical challenges for the Company and its customers. My testimony seeks to move resolution of these issues forward, but resists recommendations in parties' testimony that would make today's difficult wildfire insurance challenges worse.

[3] PAC/600, Steward/3-4.
[4] *See* SB0224 (utah.gov).

Proposals that would essentially disallow significant portions of the insurance expenses the Company incurs disregard the threat to the Company's credit ratings and general financial health brought on by wildfire liability developments—in Oregon and throughout the West. At a time when the costs to insure the Company and its customers against unexpected liabilities is increasing and affecting the Company's financial health, it would be counter-productive to introduce an unprecedented "sharing" mechanism that prevents recovery of prudent expenses needed to protect against unbounded liability risks. The Company's concerns with the sharing proposals that impact wildfire restoration and insurance costs are also discussed in the reply testimony of Company witness Matthew D. McVee.[5]

## II. THE CREATION OF A CFF THAT ADDRESSES THE RISKS AND CONSEQUENCES OF CATASTROPHIC WILDFIRES SHOULD BE CONSIDERED IN A SEPARATE PROCEEDING

**Q. Please describe the Company's updated proposal for the CFF in this proceeding.**

A. The Company is withdrawing the CFF issues from its requests for relief in this proceeding. The Company will return to the Commission in the future, in a separate proceeding, for approval of a CFF proposal or other mechanism to respond to this unbounded risk of catastrophic liability.

**Q. Why are you proposing to request approval of the CFF in a future proceeding in lieu of consideration in this proceeding?**

A. The Commission has recognized that "public policy and regulatory solutions to the problem of unbounded wildfire liability are urgently needed."[6] For PacifiCorp, these

[5] PAC/2000, McVee/28-44.
[6] *In the Matter of PacifiCorp, dba Pacific Power, Advice No. 23-018 (ADV 1545), Modifications to Rule 4, Application for Electrical* Service, Docket No. UE 428, Order No. 24-021, at 1 (May 30, 2024).

issues were urgent when we initiated stakeholder workshop discussions on wildfire issues last September, and they remain so today. Testimony on behalf of Staff, CUB, and AWEC all acknowledged the importance of considering innovative ways of managing recovery of wildfire insurance.[7] At the same time, their testimony argues that the CFF, or other similarly purposed means of cost [8] should be developed further before Commission approval.

A proceeding limited to CFF will enable PacifiCorp to further develop its proposal, consider and incorporate, if appropriate, the thoughtful feedback received from Staff, CUB and AWEC in this proceeding, and to bring forward any agreements reached in the multi-state stakeholder discussions. Additionally, on March 13, 2024, Utah Governor Spencer Cox signed into law SB 224, which in part enacted new Utah Code § 54-24-301. While I am not an attorney, it is my understanding that Utah Code § 54-24-301(2) allows a large-scale electric utility, such as the Company, to create a Utah Fire Fund to supplement other forms of insurance to pay third-party claims for fires that occur in Utah. The law also notably establishes a cap on non-economic damages. The Company is evaluating the best approach to implement this new law and, specifically, whether or how it may work in in conjunction with a multi-state CFF.

[7] *See, e.g.,* Staff/2200, Brewer, Pileggi, and Stevens/7 ("Staff is not opposed to exploring a CFF. … PacifiCorp is attempting to solve a very difficult issue, and the CFF is one potential solution.").
[8] *See* CUB/100, Jenks/55-66 (CUB's testimony details the California Wildfire Fund, as an alternative structure for recovering the costs of catastrophic events); AWEC/100, Wilcox/10 (recommending the Commission consider securitization as authorized by Oregon law).

**Q. What is the impact in this proceeding of the Company's withdrawal of the CFF?**

A. The withdrawal of the request in this proceeding reduces the requested overall increase by $77.7 million, or 4.3 percent.

**Q. Does the Company have a proposed timeline for filing the CFF proceeding?**

A. The Company expects to initiate the CFF proceeding in calendar year 2025, so it would not compromise the Commission's resources devoted to this general rate case (GRC). However, the pressing need to identify and implement workable tools for addressing risks associated with catastrophic wildfire should not await the Company's next general rate case or be otherwise procedurally hobbled.

The Company continues to host multi-state stakeholder discussions (which began in September 2023) seeking input on treatment of wildfire insurance issues, including a CFF. If the multi-state stakeholder process results in an agreed proposal that PacifiCorp can bring before the state commissions for approval, the Company would propose filing that proposal as soon as it is completed to initiate the CFF proceeding.

This approach would enable continued negotiations over the size, structure, governance, and cost allocation of the CFF. The pause in Commission consideration of the CFF would separate those negotiations from the other complex issues that must be resolved in this GRC by the end of calendar year 2024. The pause would also facilitate potential discussions of CFF or other wildfire legislation during the 2025 Oregon legislative session without attempting to simultaneously address those issues in a Commission proceeding. If neither the multi-state stakeholder process nor the legislative session result in a sufficient means to address the issue, the Company

expects to initiate a state-specific regulatory proposal, which would likely forgo the benefit of pooling risk.

**Q. Even though the Company is withdrawing the CFF for this proceeding, would you like to respond to certain comments and assertions by CUB and Staff to clarify the record for future conversations?**

A. Yes. First, both Staff and CUB claim that the proposals have not progressed enough or "lack certainty and transparency."[9] As noted in direct testimony by both myself and Company witness Robert Mudge, the risks around wildfire liability and available insurance costs and coverage are in a dynamic state but a priority that needs to be addressed in the West. The Company has undertaken a number of workshops with stakeholders across multiple states to try to collaborate on solutions that would support better certainty for customers and financial stability for the Company. While those discussions have not progressed at a pace that would enable finalizing details for implementation of the full mechanics for a CFF at this time, I believe the workshops have been a valuable tool for information sharing and engagement in a non-litigious and confidential forum to allow for open conversations. CUB's allegation that the Company is withholding details of a proposal ("this regulatory knowledge is locked within PacifiCorp's management"[10]) is incorrect as the Company has undertaken a collaborative approach on, and has been seeking constructive input for, this novel issue. Additionally, the Company was disappointed with CUB's characterization of the workshops ("[the proposal is] concurrently being

[9] Staff/2200, Brewer, Pileggi, and Stevens/7; CUB/100, Jenks/33.
[10] CUB/100, Jenks/36.

decided in separate confidential forums outside of the Commission's overview, leading to a disjointed and foggy understanding of where we stand on how these tariffs will operate"[11]) and instead used testimony rather than the collaboration process for meaningful feedback. The Commission has a long history of encouraging stakeholder engagement on issues and I would ask the Commission to encourage active and constructive engagement by participants as these efforts continue.

**Q. CUB suggests that the Company has already booked liability for past fire events into the deferral pending in docket UM 2292, related to wildfire liability for 2020 wildfires in Oregon, and that the Company has not answered a question on whether the liability costs for past events would be recovered through the CFF.[12] How do you respond?**

A. I would like to clarify that the Company has *not* booked wildfire liabilities into a regulatory asset account as CUB suggests because the Company's request for approval of the deferral in docket UM 2292 is outstanding and a decision on probable recovery has not been made. In its application in UM 2292, the Company stated that it "requests that the Commission delay consideration of the approval of this deferral until the costs and the impact on the financial stability of the Company are more fully known."[13] To date, the Company has not sought action on its deferral request and the Company will not book costs into that deferral until it is approved. Before the Company could obtain any recovery of these costs, several steps would have to occur, all of which would occur outside of this GRC. First, the Commission would need to

[11] CUB/100, Jenks/36.
[12] CUB/100, Jenks/34-35.
[13] *In the Matter of PacifiCorp dba Pacific Power, Application for Authorization to Defer Costs Related to Wildfire Liability,* Docket No. UM 2292, Initial Filing (June 15, 2023) at page 1.

take action on the deferral application in docket UM 2292. If approved, recovery of the costs would then be considered through a separate future proceeding. Recovery of past liabilities through the CFF is not presumed or requested in the Company's proposal in this GRC.

**Q. Staff presents an alternative analysis for considerations of state allocation factors for the CFF.[14] Would you please comment on Staff's analysis?**

A. Yes. First and foremost, I respect and appreciate Staff's constructive consideration of alternative allocations for the CFF. I generally agree with Staff's "overarching philosophy" that the allocations should consider the probability and potential magnitude of damages.[15] As I discussed in my direct testimony, the allocation framework should also acknowledge that the fund is a form of insurance. While Staff's methodology recognizes the risk and magnitude of wildfires, it does not take into account liabilities associated with wildfires and how different state constructs may influence the magnitude of the liabilities, not just the magnitude of damages. For example, as I noted earlier, Utah recently passed SB 224, which among other things, includes a cap on the amount of non-economic damages that could be awarded to plaintiffs filing a fire claim. For the discussions going forward, I believe the different state liability laws are a key consideration for the relative risks of liability across states and therefore should be considered for allocations.

[14] Staff/2200, Brewer, Pileggi, and Stevens/23-32.
[15] *Id.* Brewer, Pileggi, and Stevens/24.

**Q. CUB states that PacifiCorp is asking customers "to pay for increased insurance premiums and contribute to a liability fund…without a reciprocal agreement from the Company – and its shareholders – to change the Company's performance." Do you agree that the Company's performance does not reflect a duty to "responsibly manage its assets to avoid wildfire liability and any resulting financial instability?"[16]**

A. Absolutely not. CUB's assertion overlooks a number of facts. Company witness Cindy A. Crane outlines in her direct testimony multiple actions the Company is taking to respond to escalating risks of wildfire and to ensure the Company's financial stability and the continued provision of safe reliable service to customers.[17] Additionally, as discussed in my direct testimony and the direct testimony of Company witness Allen Berreth, the Company devotes substantial resources and efforts to address the risk of wildfires. However, the Company's mitigation efforts cannot eliminate wildfire risks or the view that the role of the utility and its investors is to have "deep pockets."[18] Responsibility to mitigate wildfires is distributed across numerous agencies and individuals whose actions or inactions may result in damages regardless of a utility's performance. But until broader societal changes can be accomplished, PacifiCorp needs regulatory solutions as part of a comprehensive approach to managing and addressing this unbounded risk.

[16] CUB/100, Jenks/40.
[17] PAC/100, Crane/7-8.
[18] CUB/100, Jenks/43.

## III. THE COMMISSION SHOULD AUTHORIZE RECOVERY OF FORECASTED AND DEFERRED EXCESS LIABILITY INSURANCE PREMIUMS USING THE ICA RIDER PROPOSED BY THE COMPANY

**Q. Please summarize the Company's proposal for recovery of forecasted and deferred excess liability insurance expenses.**

A. The Company proposed that recovery of the excess liability insurance expenses approved for deferral in docket UM 2301 be recovered over three years, starting in January 2025. The deferred amounts, along with the forecasted ongoing excess liability premiums for the test year, would both be recovered through the ICA rider, Schedule 80. This would enable recovery of necessary insurance expense while the Commission considers the appropriate size and structure of an insurance mechanism and CFF. It also recognizes the emergence of excess liability insurance costs as an expense category of a greater magnitude and import than in past rate cases, and begins the practice of tracking and accounting for excess liability insurance costs (whether commercial policy premiums or self-insurance costs) in a way that will speed the implementation of an Insurance Mechanism approved by the Commission.

**Q. Is the Company proposing to recover any amounts of insurance expense that would not have been recovered in the absence of the ICA proposal?**

A. No. From a cost recovery perspective, the Company is proposing nothing different from past practice in Commission ratemaking. As discussed in my direct testimony, PacifiCorp included a forecast of commercial premiums for the test period in this docket, along with the proposed amortization (three years) for the deferral approved in docket UM 2301.[19] The only excess liability insurance costs the Company

[19] PAC/600, Steward/24-25.

proposes to recover in this proceeding are in the same categories of expense it has recovered in the past: the cost of insurance premiums previously paid and deferred for recovery (in docket UM 2301), and the forecasted amount of insurance premiums that will be due in the test year.

**Q. Does withdrawal of the CFF from this proceeding affect the Company's proposal to collect deferred and ongoing excess liability insurance costs through the ICA rider?**

A. No. The withdrawal only affects the Commission's consideration of the CFF, a catastrophic fund that is triggered if the Company exhausts the proceeds of commercial or self-insurance due to a wildfire event. PacifiCorp continues to support removing excess liability premiums (or self-insurance amounts) from base rates and incorporating them in Schedule 80 for collection through the ICA rider.

**Q. How does the Company respond to testimony that questions the recovery of excess liability insurance expenses through the ICA rather than in base rates?**

A. Staff witness Stevens notes that Staff "generally supports the concept behind the Insurance Mechanism,"[20] but "prefers to address both the Insurance Mechanism and the vehicle to recover costs related to it in a singular docket."[21] AWEC witness Wilcox asserts that "allowance of ICA in rates, even conceptually, has not been justified," and should be rejected "until such time that the Company makes a clear showing that the Insurance Mechanism will result in customer benefits."[22]

The Company proposes the ICA as a means to begin the process of future-

[20] Staff/1900, Stevens/39.
[21] *Id.*, at 39-40.
[22] AWEC/100, Wilcox/17.

proofing its insurance portfolio at a time when the market for wildfire insurance is exhibiting extreme volatility. Starting in 2025, the ICA would recover deferred insurance premium payments (over three years) and forecasted excess liability insurance expenses. The "allowance of ICA in rates," as AWEC witness Wilcox puts it, allows only the recovery of traditionally recoverable deferred and ongoing insurance premiums. The ICA cost recovery rider adds nothing to the insurance expense amounts recoverable in rates.

If the Commission approves an insurance mechanism in a future proceeding, funds collected from rates via the ICA could be shifted away from paying commercial insurance premiums (if costs were excessive and/or coverage levels sufficiently diminished) and toward funding a self-insurance reserve. The Commission's authorization of recovery through an ICA in this case would have two advantages over continued collection of excess liability insurance expenses in base rates.

First, authorizing the ICA in this case would offer the Commission and the Company more flexibility sooner if the insurance market makes commercial insurance unreasonably expensive or insufficiently available. The Company faces an August 15 deadline each year for making decisions on commercial insurance procurement, so the establishment of an ICA to manage insurance expense can positively impact insurance coverage decisions sooner if it is approved in this proceeding.

Second, establishing the ICA as a separate insurance recovery tariff would facilitate Commission approval of a self-insurance vehicle in a future insurance

mechanism proceeding. The Company could implement a Commission order approving self-insurance without the need to revisit or amend the rates and tariffs approved in this proceeding that contemplate recovery only in base rates. If the Commission chose not to implement a self-insurance vehicle, there would be no impact on customers' rates. As I stated in my direct testimony, allowing collection of insurance expense through the ICA in this proceeding neither increases nor decreases the amount of deferred or ongoing insurances expense included in customer rates. In either scenario, approved rates would include only recovery for currently deferred and forecasted ongoing insurance expenses. Approval of the creation and funding of a self-insurance mechanism would await a future Commission order.

**Q. CUB states "self-insurance as a misnomer."[23] Even though the Company is not seeking to include self-insurance for excess liability in rates in this case, would you like to clarify the role of self-insurance?**

A. Yes. In contrast to CUB's characterization that self-insurance is "just money out of ratepayer's pockets to protect shareholders from feeling the impacts of PacifiCorp's liabilities,"[24] self-insurance can potentially provide a cost saving tool for customers. Insurance is, and has always been, a prudent and necessary aspect of being able to serve customers. Where commercial insurance is not available or feasible, the Company has implemented—and the Commission has approved—self-insurance in rates. Today, the Company's rates already include self-insurance for liability for

[23] CUB/100, Jenks 51.
[24] *Id.*

claims less than $10 million, property damage for poles and wires, and health insurance for employees. A move to self-insurance for excess liability would not be inconsistent with precedent.

**Q. Please describe the arguments in Staff's testimony for "sharing" of excess liability insurance expenses.**

A. Staff witnesses propose that all insurance, either commercially obtained or self-insurance, be shared 20 percent by the utility on a going forward basis."[25] Staff states that the "20 percent share for PAC is proposed for two reasons: to incentivize the Company to purchase in a least cost manner; and [t]o recognize that the 2020 fires play a role in the increase in insurance costs."[26]

**Q. How does the Company respond to Staff's proposal?**

A. Staff's proposal is unjustified and counterproductive. While Staff characterizes its proposal as "sharing," it effectively institutes a disallowance of one-fifth of the Company's current and future expenses for insurance coverage, no matter how prudently the Company behaves in its procurement of necessary coverage. Moreover, Staff's proposal does not constitute "sharing" of the risks and benefits of insurance coverage with customers.

**Q. Why does Staff's proposal not constitute "sharing"?**

A. Put simply, it ignores the central purpose of insurance. Individuals and businesses buy insurance to protect against unplanned risk. Paying an insurance premium is a sensible hedge against paying much higher costs that would come due if liability

[25] Staff/1900, Stevens/40.
[26] Staff/1600, Peterson/25-26.

arose and no insurance was purchased. The "cost" of insurance is the premium, or, in the case of self-insurance, the funds reserved for payment of claims. The basic transaction is no different if one is insuring a home, a car, or a business against liability claims. But insurance is particularly critical to utilities. As Company witness Coleman's direct testimony explained: "Utilities maintain insurance at different levels when compared to other industries in order to avoid the volatility of claims on customer rates, especially in an environment when the utility does not directly control the pricing of the service it provides."[27] Utilities incur insurance costs not to boost profits, but to protect themselves and their customers from exposure to large claims that could impact the utility's financial stability and its rates.

Those who purchase insurance incur the costs because they promise a substantial benefit. The benefit is the payment that covers large claims covered by excess liability insurance. As Company witness Coleman points out: "Oregon customers have benefited materially from excess liability insurance coverage including recovery of over $450 million system-wide since 2010, which offsets claims paid by PacifiCorp. These insurance recoveries directly reduce the cost of claims paid, providing financial stability for both the Company and its customers."

If Staff's proposal were actually "sharing," both the costs and the benefits of insurance expenses would be shared. In that case, a 20 percent sharing of the benefits of excess liability insurance Company witness Coleman documents would mean $90 million of the $450 million recovered through insurance should flow directly to the Company. The $90 million in that example would be recoverable from customers as

[27] PAC/700, Coleman/9.

the trade for the Company's 20 percent share of the costs that made the benefit possible.

The Company would not propose a "sharing" mechanism that would create such an anomalous result. The costs and benefits of insurance are inherently asymmetrical (that is what makes insurance worth having), but they are inextricably linked (as anyone has learned who tried to make a claim on a lapsed policy). When the Company purchases insurance, it does so to mitigate its risks and the risks to its customers. When an insurance policy pays benefits to offset claims, the financial exposure of both the Company and its customers is substantially reduced. This is the fundamental reason why purchasing excess liability and other forms of insurance has historically been recognized as a prudent expense in utility ratemaking. If "sharing" applies to costs while not affecting benefits, it is not sharing, but rather an arbitrary disallowance of a prudent expense.

**Q. How does the Company respond to Staff's arguments regarding the incentives for the Company in its proposal?**

A. Staff argues that disallowing 20 percent of its costs of obtaining insurance (whether commercial policies or through a self-insurance reserve) would "incentivize the Company to purchase [insurance] in a least cost manner."[28] This purported incentive is misplaced and counter-productive in today's wildfire insurance market.

When it approved deferral of PacifiCorp's insurance costs in docket UM 2301, the Commission documented an "increase from the $29 million currently in rates to $125 million (a $96 million increase) for the policy period starting

[28] Staff/1600, Peterson/25.

August 15, 2023.[29] Staff's testimony in this case recognizes that total Company insurance costs, exclusive of workers' compensation, "increased by 25.25 percent from the [Base Year] to the [Test Year]."[30] The extraordinary increases in the cost of wildfire insurance, and the increasing difficulty of procuring it in some states, is what has brought this issue to the forefront of this proceeding.

The wildfire liability insurance market is not one in which reducing recoverable expenses gives the Company an incentive to contain costs. Rather, the volatility of the market is driving costs extremely high for all Western utilities. The only incentive that preventing recovery of 20 percent of the Company's insurance expenses provides in today's market is an incentive to purchase insurance that may provide suboptimal coverage (which neither the Company nor its customers can realistically afford when insuring against wildfire claims).

The application of the proposal to self-insurance is especially difficult to understand. As explained in my direct testimony, a shift to self-insurance would be prudent if it provides similar coverage to commercial insurance at a lower cost. Self-insurance would involve replacing commercial insurance premium expenses with expenditures to fund a self-insurance reserve. Staff's proposal would require that only 80 percent of the self-insurance reserve expense would be recoverable in rates. If the Commission finds a self-insurance reserve amount prudent, Staff proposes the Commission nevertheless disallow the Company's recovery of the full funding of the reserve.

[29] *In the Matter of PacifiCorp dba Pacific Power, Application for Authorization of Deferred Accounting Related to Insurance Costs for Wildfires*, Docket No. UM 2301, Order No. 24-021, Appendix A, at 4-5 (Jan. 24, 2024).
[30] Staff/1600, Peterson/19.

The key incentive for efficient use of insurance is typically achieved through deductible amounts rather than disallowance of premiums or self-insurance reserve payments. As I discussed in my direct testimony,[31] PacifiCorp's existing $10 million self-insurance retention serves this purpose by covering smaller claims so that such claims will not contribute to higher premiums in the future. The Company proposes an additional deductible, or co-insurance, component for self-insurance approved as part of an insurance mechanism.[32] These deductibles give the Company incentives to manage current and future insurance claims efficiently, without imposing the unjustified and ineffective disallowances called for in Staff's proposal.

**Q. How does the Company respond to Staff's reasoning regarding the impact of the 2020 fires?**

A. Company witness Coleman's reply testimony contests Staff's factually inaccurate argument that the 2020 fires in Oregon caused the increase in the Company's excess liability insurance rates. I will only note that this rationale for Staff's "incentive" disallowance will not make the proposal any more of a useful incentive than Staff's claim, discussed above, that the 20 percent disallowance will positively influence the Company's choices when it seeks expensive and scarce wildfire insurance.

## IV. CONCLUSION

**Q. Please summarize your recommendation to the Commission.**

A. I recommend that the Commission approve recovery of the deferred insurance premium costs and the test period insurance premiums through the ICA.

[31] PAC/600, Steward/22.
[32] *Id.* PacifiCorp proposes that the Company would pay 2.5 percent of claims over $350 million (total Company), with an annual cap of $10 million (total Company).

**Q. Does this conclude your reply testimony?**

A. Yes, it does.

Docket No. UE 433
Exhibit PAC/2400
Witness: Mariya V. Coleman

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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# Reply Testimony of Mariya V. Coleman

**July 2024**

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## ATTACHED EXHIBITS

Exhibit PAC/2401—OPUC Response to PacifiCorp Data Request 15

**Q. Are you the same Mariya V. Coleman that previously provided direct testimony in this case on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?**

A. Yes.

## I. PURPOSE AND SUMMARY

**Q. What is the purpose of your reply testimony?**

A. The purpose of my reply testimony is to respond to the Public Utility Commission of Oregon (Commission) Staff witness Nicola Peterson's (Staff) testimony and recommendation regarding the amortization of the deferred amounts of excess liability insurance premiums authorized to be recorded under docket UM 2301.[1]

**Q. Can you please summarize Staff's recommendation.**

A. Staff recommends that PacifiCorp should not be able to recover 20 percent of the deferred amount recorded under docket UM 2301. Two reasons were provided for this recommendation: (1) "To incentivize the Company to purchase in a least cost manner," and (2) "To recognize that the 2020 fires play a role in the increase in insurance costs."[2]

Company witness Matthew D. McVee provides a response to Staff recommendation[3]—whereas my testimony will more narrowly focus on the claim that the referenced "2020 fires" played a role in the deferred amounts recorded under docket UM 2301.

[1] *In the Matter of PacifiCorp, dba Pacific Power, Application for Authorization of Deferred Accounting Related to Insurance Costs for Wildfires*, Docket No. UM 2301, Order No. 24-021 (Jan. 24, 2024).
[2] Staff/1600, Peterson/25.
[3] PAC/200, McVee.

**Q. Can you please summarize the recommendation in your reply testimony?**

A. I recommended that the Commission find that Staff's claim that the "2020 fires play[ed] a role" in the excess liability insurance premiums authorized to be recorded under docket UM 2301 is unsupported and does not provide sufficient justification for Staff's recommendation of a 20 percent disallowance.

## II. AMORTIZATION OF DOCKET UM 2301 DEFERRAL

**Q. Does Staff provide a definition of the term "2020 fires" referenced in this recommendation?**

A. No. For the purposes of my reply testimony, I am assuming that the term "2020 fires" is defined as wildfires that occurred during calendar year 2020 that have been alleged to have been caused, or caused in-part, by PacifiCorp.

**Q. Does Staff provide any rationale behind the 20 percent figure referenced in the recommendation?**

A. No. The 20 percent figure appears to be an arbitrary number.

**Q. Does Staff provide any evidence or explanation in testimony on how the "2020 fires play[ed] a role" in the deferred amount of insurance premiums recorded under docket UM 2301?**

A. No.

**Q. Assuming sufficient evidence was presented in testimony to support the claim that the 2020 fires "play[ed] a role" in the costs of insurance premiums recorded under docket UM 2301, does Staff provide any policy reason why this justifies the proposed 20 percent disallowance?**

A. No.

**Q. Can you please explain how PacifiCorp procures excess liability insurance?**

A. Yes. As explained in my direct testimony, PacifiCorp's excess liability insurance is purchased as part of Berkshire Hathaway Energy's (BHE's) aggregated insurance purchases. This allows PacifiCorp to leverage BHE's size and expertise in procuring insurance coverage.[4]

**Q. When does BHE typically renew its excess liability insurance policies?**

A. As also explained in my direct testimony, excess liability insurance premiums are typically renewed every August.[5]

**Q. Has BHE renewed its policy for the August 2024-25 period?**

A. Not yet. BHE is currently negotiating through its intermediary with insurance providers to renew its policies for the August 2024-25 period. BHE anticipates securing commercial insurance coverage for this period and PacifiCorp anticipates being able to update the forecasted premium amount provided in my direct testimony with the actual policy amounts from the 2024 renewal in surrebuttal testimony. At the time of filing this reply testimony, the forecasted amount of excess liability insurance premiums provided in my direct testimony remains the Company's best estimate.

**Q. When did PacifiCorp file for an accounting order in docket UM 2301?**

A. As referenced in the reply testimony of Company witness McVee,[6] it is my understanding that PacifiCorp filed for an application for authorization for an accounting order on August 21, 2023, and the Commission granted the Company's

[4] PAC/700, Coleman/4.
[5] PAC/700, Coleman/4.
[6] PAC/2000, McVee.

application on January 24, 2024.[7] *Importantly*, this means that the Company is only seeking recovery of the incremental insurance premiums arising from its most recent policy renewal in August 2023 that are in excess of its currently approved rates established in its 2022 rate case.[8] It is my understanding that the currently approved rates from the 2022 rate case have the August 2021 policy renewal amounts embedded.

**Q. How do you respond to Staff's recommendation and claim that the "2020 fires play[ed] a role" in the amount of excess liability premiums reflected in the August 2023 policy renewal?**

A. I have several concerns with this claim. Certainly, an insurance provider can consider individual fires that may have been caused by a certain subsidiary of BHE, among other considerations, when negotiating premium amounts. However, if insurance providers were to consider the referenced "2020 fires" in the August 2023 policy renewal, such considerations should have already been embedded within the August 2021 policy renewal amounts—that are already embedded in current rates from the 2022 rate case. It does not seem likely that an insurance company would choose to ignore such considerations from calendar year 2020 in the 2021 renewal, and then for the first time consider the "2020 fires" in a later policy renewal. This is important because, given the timing of the deferred accounting order in docket UM 2301, the

[7] *In the Matter of PacifiCorp, dba Pacific Power, Application for Authorization of Deferred Accounting Related to Insurance Costs for Wildfires*, Docket No. UM 2301, Order No. 24-021 (Jan. 24, 2024).
[8] In the Matter of *Pacific Corp dba Pacific Power, Request for a General Rate Revision,* Docket No. UE 399, Order No. 23-047 (Feb. 17, 2022).

deferred amounts sought to be recovered are only the amounts incremental from the 2021 policy renewal (currently embedded in rates) and the 2023 policy renewal.[9]

Second, Staff's claim seems to overlook market trends and the increase in premium amounts paid by other peer utilities. As explained in my direct testimony, BHE is one of many participants in the market for insurance coverage, along with other utilities, that has been impacted by ongoing wildfire risk in the Western United States.[10] In direct testimony, Company witness Robert S. Mudge provides further explanation of how wildfire risk in the West has impacted these markets, providing specific examples of other utilities experiencing increases in their premium amounts, including Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric, Avista Corporation, and Idaho Power Company.[11] So, while fires that occurred several years ago may have "play[ed] a role" in the premium amounts associated with the August 2023 policy renewal, the significance and impact of that role is entirely speculative in the broader market for commercial insurance and does not provide sufficient justification for the proposed 20 percent disallowance.

Third, Staff also appears to not acknowledge the incremental increase in the volume of excess liability purchased between the 2021 policy renewal, which is currently embedded in rates, and the 2023 policy renewal underlying the amounts recorded under docket UM 2301. In other words, that the premium amount contained in the 2023 policy renewal is reflective of both the increased market cost *and* volume of coverage purchased. For instance, the 2023 policy renewal increased the total

[9] PAC/2000, McVee.
[10] PAC/700, Coleman/6.
[11] PAC/500, Mudge/5-13.

excess liability sub-limit in Oregon from $170,500,000 to $348,250,000, as illustrated in Table 1:

**Table 1: Summary of PacifiCorp's Excess Liability Insurance Limits**

| PacifiCorp | 2023 | 2022 | 2021 | 2020 | 2019 | 2018 |
|---|---|---|---|---|---|---|
| Total Excess Liability Limit | $542,500,000 | $530,000,000 | $515,000,000 | $517,500,000 | $517,500,000 | $485,000,000 |
| Wildfire Sub limits: | | | | | | |
| CA | $344,750,000 | $145,000,000 | $145,000,000 | $95,000,000 | $98,000,000 | $147,500,000 |
| OR/WA | OR $348,250,000<br>WA $363,250,000 | $188,000,000 | $170,500,000 | $415,000,000 | $415,000,000 | |
| ID/UT/WY | $458,250,000 | $232,500,000 | $215,000,000 | $427,500,000 | $427,500,000 | |

Fourth, to the extent Staff is inferring that the verdict of *James v. PacifiCorp*[12] materially impacted the 2023 renewal, I also believe that supposition is unsupported. The Company has not, and will not, file any J*ames*-related claims with its excess liability insurance providers. Any claims arising from the *James* litigation that are recoverable from excess liability insurance would have to be paid from the Company's excess liability policies in effect during the 2020 policy year. The 2020 policy year included several extraordinary wildfires, and the Company's 2020 insurance benefits were already exhausted other than those related to the *James* verdict in 2023. For that reason, none of the *James* damages (whatever amount they may total after appeals are complete) will be paid for by excess liability insurance or become part of the Company's insured loss history that is a consideration of insurance companies across industries (including automobile, home, etc.) in renewing insurance policies.

Fifth, Staff's recommendation provides no citation to authority that supports the principal that insurance premium costs incurred by a utility should be disallowed, in whole or in part, as a basis for setting just and reasonable rates. As referenced in

[12] No. 20-CV-33885 (Cir. Ct. Multnomah Cnty., June 12, 2023) ("James").

the reply testimony of Company witness McVee, the California Public Utilities Commission has previously rejected similar arguments, stating: "[t]he Commission has consistently authorized rate recovery of wildfire liability insurance premium costs as a standard cost of service and has never accepted intervenor arguments that incurred premium costs should be disallowed, in whole or in part, to shareholders."[13]

Lastly, as mentioned above, Staff provides no explanation or evidence in testimony to support the claim that fires that occurred in 2020 played a significant enough role in the August 2023 policy renewal to warrant the 20 percent disallowance recommendation. In preparing this reply testimony, a data request was issued to Staff to provide evidence to support their claim.[14] In response to the data request, the evidence Staff provided to establish causation between the referenced "2020 fires" and the incremental costs reflected August 2023 policy renewal were statements that these particular fires were significant, destructive, and resulted in lawsuits against the Company.[15] Staff also highlighted the Company's Application in this proceeding, which explains the general impact of wildfires on commercial insurance markets. I agree with the representations within the Application that the commercial insurance market, that utilities participate in, has reacted to wildfire risk in the West. However, based on my experiences and my assessment of the evidence presented by Staff, I believe the claim that the "2020 fires" impacted the commercial insurance market in 2023 to the degree to warrant a 20 percent disallowance is

[13] PAC/2000, McVee; Public Utilities Commission of the State of California, *Application of Southern California Edison Company (U338E) for Authorization to Recover Costs Related to 2018-2020 Wildfire Insurance Premiums Recorded in its Wildfire Expense Memorandum Account*, Application No. 19-07-020, Decision No. 20-09-024 (Sept. 9, 2020).
[14] PAC/2401.
[15] PAC/2401.

conclusory, speculative, and unsupported. Even assuming that these fires did play a material role in the 2023 policy renewal, Staff provides no policy reason why this would justify a 20 percent disallowance. I believe this is an important consideration for the Commission because this claim is one of the two premises underlying Staff's disallowance recommendation.

## III. CONCLUSION

**Q. Please summarize your recommendation to the Commission.**

A. For the reasons set forth above, I recommend that the Commission not adopt Staff' recommendation to impose a 20 percent disallowance of the deferred premium amounts recorded under docket UM 2301.

**Q. Does this conclude your reply testimony?**

A. Yes.

Docket No. UE 433
Exhibit PAC/2401
Witness: Mariya V. Coleman

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Mariya V. Coleman**

**OPUC Response to PacifiCorp Data Request 15**

**July 2024**

Date: July 17, 2024

TO:
DATA REQUEST RESPONSE CENTER
PACIFICORP
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FROM: Nicola Peterson
Senior Telecom Analyst
Rates Division

**OREGON PUBLIC UTILITY COMMISSION**
**Docket No. UE 433 – PacifiCorp Data Request No. 15**

**Data Request No 15:**

Please refer to Staff/1600, Peterson/25-26, where Staff provides testimony pertaining to the amortization of the deferral authorized in Docket No. UM 2301. In particular, Staff recommends that "the Company share in the excess insurance costs in the amount of 20 percent." Staff provides two reasons for this recommendation, one of which includes "that the 2020 fires play a role in the increase in insurance costs." Please provide any and all evidence Staff relied upon for the conclusion that the "2020 fires" played a role in the amount of insurance premiums recorded in the deferral authorized in Docket No. UM 2301

**Staff Response No 15:**

Staff objects to this request as overly broad and unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding this objection, Staff responds as follows:

Staff's view that the 2020 fires have played a role in the increase in insurance premiums is informed by the significance of these fires to Oregon as a whole and to PacifiCorp specifically, and the effect PacifiCorp stated wildfires have on the liability insurance premiums deferred in UM 2301.

The 2020 fires were the most destructive fires in Oregon history[1] with regards to property damage and the second most destructive, after 2012, in regard to acres burned.[2] As a result of the 2020 Wildfires, a significant number of lawsuits were filed against PacifiCorp in Oregon and California.[3]

[1] Various news reports: Fires in Oregon, California and Washington spread, death toll rises (cnbc.com), Wildfire cuts swath of destruction in southern Oregon; Phoenix and Talent 'pretty well devastated' - oregonlive.com.
[2] https://projects.oregonlive.com/data-points/bootleg/table.html.
[3] U.S Securities and Exchange Commission, March 31, 2024, Form 10-Q/Item 1. Legal Proceedings/Page 188.

In its UM 2301 Initial Application, filed in August 2023, PacifiCorp states: “Wildfires across the western United States have resulted in significantly increasing wildfire costs and an inability to acquire insurance at rates and coverage levels that have been consistent with past premiums.” Also, the Company states “because the wildfire risk for utilities in the western United States has radically changed in the past few years, the premiums for available commercial insurance have significantly increased.”

Docket No. UE 433
Exhibit PAC/2500
Witness: Rick T. Link

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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# Reply Testimony of Rick T. Link

**July 2024**

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**Q. Are you the same Rick T. Link who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or Company)?**

A. Yes.

## I. PURPOSE OF TESTIMONY

**Q. What is the purpose of your testimony in this proceeding?**

A. My testimony responds to the testimony of Public Utility Commission of Oregon (Commission) Staff (Staff) witness Sudeshna Pal regarding the prudence of PacifiCorp's investment in the Gateway South transmission line.

**Q. Are you adopting the prefiled direct testimony of any PacifiCorp witnesses?**

A. Yes. I am adopting the prefiled direct testimony of Company witness Thomas R. Burns.

**Q. Please summarize your testimony.**

A. I discuss the Commission's prudency standard and relevant decision timelines for evaluating utility investments; PacifiCorp's prioritization of Gateway South; defend my economic analyses; and respond to Staff's concerns regarding purported increased market exposure, failure to incorporate impacts from the Ozone Transport Rule (OTR), and several concerns related to coal retirements and recent wildfire liabilities.

## II. GATEWAY SOUTH

### A. Prudence Standard and Decision Timeline

**Q. As an initial matter, what is your understanding of the Commission's prudence standard?**

A. While I am not a lawyer, my general understanding is that the Commission examines

whether a decision was reasonable based on what was known, or reasonably should have been known, at the time the decision was made. Hindsight review is impermissible, because it would rely on information that was not available at the time the decision was made.

**Q. Does the Commission's prudency standard require utilities to demonstrate its actions result in customer benefits only in terms of cost?**

A. No. While my testimony demonstrates that Gateway South and the associated wind resources are lower cost than other resource alternatives, a reduction in customer costs is not a prerequisite for establishing prudence. Relevant here, any time PacifiCorp is required by federal reliability or interconnection agreements to build transmission network upgrades, these actions could result in costs to customers. As I understand it, the prudence standard evaluates whether a utility's decisions are reasonable based on what was known or knowable, and is not explicitly tied to potential cost savings.

**Q. Are there additional considerations in a prudence review if the resource decision was addressed in a prior integrated resource plan (IRP) or request for proposal (RFP)?**

A. Yes. Turning first to IRPs, the Commission has explained the meaning of acknowledgment of an IRP as follows:

> In reviewing an IRP, we examine the resource activities in the Action Plan and determine, given the information available at the time, whether to acknowledge them based on the reasonableness of those actions. Our decision to acknowledge or not acknowledge an action item does not constitute ratemaking. The question of whether a specific investment made by a utility in its planning process was prudent will be independently examined in a subsequent rate proceeding. Acknowledgment, or

> non-acknowledgment, of an IRP is a relevant but not exclusive consideration in our subsequent examination of whether the utility's resource investment is prudent and should be recovered from customers.[1]

The Commission has found that acknowledgement of the IRP may be used as evidence to support a finding of prudence:

> Consistency of resource investments with least-cost planning principles will be an additional factor that the Commission will consider in judging prudence. When a plan is acknowledged by the Commission, it will become a working document for use by the utility, the Commission, and any other interested party in a rate case or other proceeding before the Commission, such as the review of avoided costs. Consistency with the plan may be evidence in support of favorable rate-making treatment of the action, although it is not a guarantee of favorable treatment. Similarly, inconsistency with the plan will not necessarily lead to unfavorable rate-making treatment, although the utility will need to explain and justify why it took an action inconsistent with the plan.[2]

The Commission has further explained that it "gives considerable weight to actions that are consistent with an acknowledged IRP, and consistency with the plan is evidence to support favorable rate-making treatment of the action."[3] The Commission continued: "Although the IRP process is not a legal prerequisite for a utility to seek recovery of investments in rates, we have repeatedly stated that the IRP process serves as a complement to the rate-making process and reduces the uncertainty of recovery."[4] In the Commission's view, the IRP process "enhances the quality of information available to the utility and leads to better resource decision-making."[5]

[1] Order No. 22-178 at 4.
[2] Order No. 89-507 at 307.
[3] *In re PacifiCorp's 2012 Rate Case*, Docket No. UE 246, Order No. 12-493 at 28 (Dec. 20, 2012).
[4] Order No. 12-493 at 28.
[5] *Id.* at n.55.

**Q. Turning to RFPs, what is the significance of the Commission acknowledging an RFP final shortlist?**

A. The Commission explained the significance of acknowledgement as follows:

> Our competitive bidding rules provide that acknowledgment of a RFP final shortlist is our finding that the final shortlist appears reasonable at the time of acknowledgment and was determined in a manner consistent with the competitive bidding rules. The shortlist acknowledgment proceeding has the same legal force and effect as a Commission acknowledged IRP in any future cost recovery proceeding.[6]

**Q. Was Gateway South included in an IRP preferred portfolio that was acknowledged by the Commission?**

A. Yes. PacifiCorp's 2021 IRP preferred portfolio included Gateway South and was acknowledged by the Commission.[7]

Though the Commission also noted that PacifiCorp's modeling of Gateway South "obscured nearly 75 percent of the cost of the transmission project in modeling results by placing it in the base case," and additionally, PacifiCorp does so "under a largely and potentially disputed interpretation of PacifiCorp's obligation to fulfill interconnection requests under its FERC-jurisdictional Open Access Transmission Tariff (OATT)."[8]

My direct testimony, as supplemented by this reply testimony, provides the complete economic justifications that support the need for Gateway South, while

[6] Order No. 21-437 at 12.
[7] *In re PacifiCorp's 2021 IRP,* Docket No. LC 77, Order No. 22-178, at 11 (May 23, 2022) ("Ultimately, through the iterative IRP process and the transmission workshop held in this proceeding in February, we believe PacifiCorp was able to produce sufficient information to persuade us that the Gateway South project is a reasonable project supported by a combination of factors including retail ratepayer access to low-cost generation, reliability benefits demonstrated in multiple cycles of regional transmission planning, and some level of independent obligation to interconnect generators under federal law").
[8] *Id.* at 11-12.

Company witness Richard A. Vail's testimony provides the Federal Energy Regulatory Commission (FERC)-jurisdictional requirements related to the Company's OATT and federal reliability standards.

**Q. Was Gateway South addressed in an RFP?**

A. Yes. PacifiCorp's 2020 All-Source RFP (2020AS RFP) included resource bids that relied on construction of Gateway South to interconnect to PacifiCorp's transmission system.[9] Therefore, when evaluating bids in the 2020AS RFP, PacifiCorp was also necessarily evaluating Gateway South given the interdependence of the bids and the transmission line.

**Q. Did the Commission acknowledge the final shortlist of bids from the 2020AS RFP that included bids that were reliant on Gateway South to interconnect?**

A. Yes.

**Q. When did PacifiCorp decide to move forward with construction of Gateway South?**

A. PacifiCorp received a certificate of public convenience and necessity from the Wyoming Public Service Commission on May 10, 2022, and commenced construction in June of 2022. For purposes of a prudence review, the analysis should consider what PacifiCorp knew or should have known prior to June 2022.

[9] Staff disputes the prudence of only Gateway South, although many of the benefits of Gateway South result from construction of Gateway South and Gateway West Segment D.1 (Segment D.1). For example, interconnection of resources selected in the 2020AS RFP rely on both transmission lines for interconnection. For simplicity, my testimony focuses on Gateway South even though many of the benefits I discuss require Segment D.1 too.

**Q. Taken together, what factors do you think are relevant to determine whether PacifiCorp's investments were prudent?**

A. The Commission should analyze whether these investments are prudent in terms of three issues: (1) PacifiCorp's requirement to construct transmissions facilities needed to meet federal reliability standards; (2) PacifiCorp's requirement to construct transmission facilities needed to offer open-access transmission service under its OATT; or (3) PacifiCorp's need for new resources, and its determination that Gateway South and associated wind resources were reasonably procured based on information known or knowable to the Company.

Company witness Vail addresses the first two issues, while my testimonies address the third. The Commission's analysis should focus on what PacifiCorp knew or should have known prior to June 2022, and at least from my non-lawyer perspective, this list is disjunctive—any one of these justifications supports building Gateway South and Segment D.1.

**B. Prioritization of Gateway South**

**Q. Based on its review of prior IRPs, Staff questions the decision to construct Gateway South with an in-service date at the end of 2024, and before constructing other elements of the Energy Gateway transmission expansion project.[10] How do you respond?**

A. PacifiCorp disagrees that its IRPs do not support prioritization of Gateway South. In fact, PacifiCorp's 2019 and 2021 IRPs prioritized Gateway South (together with Segment D.1) over other elements of Energy Gateway and constructing the line to

[10] Staff/1400, Pal/13-15.

achieve commercial operation at the end of 2024 is critical to allowing new generation resources to interconnect and serve customers. As explained below, the 2021 IRP (which was the operative IRP at the time the decision to construct Gateway South was made), showed a significant resource need and the least-cost, least-risk preferred portfolio chosen to meet that need included Gateway South.

**Q. Please describe the resource need shown in the 2021 IRP.**

A. PacifiCorp's most up-to-date forecast in the 2021 IRP showed a significant capacity deficit over the 20-year planning horizon—starting at 1,071 megawatts (MW) in 2021 and then rising over time to over 6,600 MW by 2040. In 2025, the first full year that Gateway South will be online, the resource need was 1,627 MW.

**Q. How does Gateway South meet the significant resource need shown in the 2021 IRP?**

A. Gateway South meets PacifiCorp's identified capacity need by enabling the interconnection of additional wind resources. Those wind resources were selected through the 2020AS RFP and represent the best available resources to help meet the resource need identified in the 2021 IRP.

**Q. Staff contends that the inclusion of Gateway South is not supported by IRP analyses and that PacifiCorp's decisions about the timing of Gateway South were driven primarily by an obligation to provide transmission and interconnection service under the OATT.[11] How do you respond?**

A. As I just described, the inclusion and timing of Gateway South in PacifiCorp's 2021 IRP was very much supported by IRP analyses. In fact, the inclusion of Gateway

[11] Staff/1400, Pal/11.

South in the 2021 IRP preferred portfolio was driven by PacifiCorp's need for new resources. Its selection as an asset coming online at the end of 2024 in the 2021 IRP preferred portfolio was a direct outcome of least-cost, least-risk planning outcomes. It was not forced as a predetermined outcome due to obligations under PacifiCorp's OATT.

**Q. Did PacifiCorp test the reasonableness of the inclusion of Gateway South as a year-end 2024 asset in the 2021 IRP preferred portfolio?**

A. Yes. PacifiCorp's 2021 IRP included a variant analysis that compares two alternative scenarios: (1) one scenario where the timing of Gateway South was based on its selection in the least-cost preferred portfolio, which coincided with the timing of the associated resources identified in the 2020AS RFP final shortlist; and (2) another scenario reflecting the least-cost, least-risk portfolio in the absence of Gateway South and the associated resources dependent on Gateway South. As demonstrated in the 2021 IRP analysis:

> Through 2040, the PVRR(d) shows that the portfolio without [Gateway South] and D.1 transmission lines is $128 million higher cost than the P02-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without the [Gateway South] and D.1 transmission lines is $260 million higher cost than the P02-MM portfolio. The risk-adjusted results indicate that the [Gateway South] and D.1 transmission lines add significant risk mitigation benefits associated with volatility in market prices, loads, hydro generation, and unplanned outages.[12]

[12] PacifiCorp's 2021 IRP, Vol. I: Chapter 9 – Modeling and Portfolio Selection Results at 274.

In addition, in the absence of Gateway South and associated resources being added by 2025, market reliance increased sharply and remained sharply elevated by an average of 20 percent throughout the study period.[13]

**Q. Was the increased reliance on market purchases absent Gateway South concerning to PacifiCorp?**

A. Yes. Leaning more heavily on the market in the near term creates real and significant reliability risks because there may not be a counterparty willing and able to sell energy in the volumes and at the time of need. As discussed in my direct testimony, the Western Electricity Coordinating Council was forecasting a Western Interconnect-wide capacity shortage during the exact time that PacifiCorp would be relying heavily on market purchases to serve customers absent Gateway South. When assessing the decision to move forward with Gateway South, I had serious concerns about our ability to provide reliable service if forced to proportionately increase the Company's reliance on market purchases in the coming years.

**Q. In addition to interconnecting additional wind resources, does Gateway South provide other resource adequacy benefits?**

A. Yes. As discussed by Company witness Vail, Gateway South allows transfers of up to 1,700 MW from eastern Wyoming to central Utah, which will mitigate resource adequacy risk by enabling more efficient movement of generation to load.

[13] *Id.* at Figure 9.17 – Increase/(Decrease) Market Purchases in the P02-MM and P02c-No GWS Portfolios; *see also Id*. at 272-279.

**Q. How do you respond to the implication in Staff's testimony that PacifiCorp should have delayed construction of Gateway South?**

A. Staff appears to assume that Gateway South may be more economic (without jeopardizing reliability) in future years. This has been disproven by the selection of Gateway South as the least-cost, least-risk means to meet PacifiCorp's imminent resource need first identified in the 2019 IRP, confirmed in the 2020AS RFP, and confirmed again in the 2021 IRP. As I previously explained, and it bears repeating, PacifiCorp did not force or hard code Gateway South's selection to meet obligations under its OATT. Selection of Gateway South and its timing in the 2021 IRP is driven by a need for new resources and is supported by least-cost, least-risk planning.

Further, the 2020AS RFP final short list and associated transmission projects, including Gateway South, demonstrated not only that they were needed consistent with analysis from the 2019 IRP, but that they also produced net benefits by its contribution to filling a significant capacity deficit. The 2021 IRP confirmed, with new tools and updated analysis, that: 1) this capacity deficit was correctly detected by the 2019 IRP; 2) is exacerbated in the absence of Gateway South; 3) Gateway South with enabled resources remained as a critical element in the least-cost, least-risk means that fills this immediate need; and 4) alternative strategies to meet the near-term need are higher risk and higher cost. In sum, the option to wait was simply untenable.

**Q. Has Staff previously acknowledged the reliability risk posed by delaying Gateway South?**

A. Yes. In its October 6, 2021, report recommending acknowledgment of the 2020AS

RFP final shortlist, including bids that relied on Gateway South, Staff noted that "market depth has been declining in recent years" and therefore delaying the Gateway South to 2027 would create a "substantial reliability risk associated with allowing a large short capacity position in 2025."[14]

**Q. Did the 2021 IRP examine potential alternatives to Gateway South?**

A. Yes. Among the many different variant portfolios, the 2021 IRP specifically examined a variant that removed Gateway South and Segment D.1 (P02c) and removed the 2020AS RFP final shortlist of bids (P02d). As discussed in detail in my direct testimony, both variants would have resulted in higher costs compared to moving forward with Gateway South.[15]

**Q. How would delay have impacted the economic benefits of the interconnecting wind resources?**

A. When PacifiCorp commenced construction in June 2022, the wind projects that rely on Gateway South were required to achieve commercial operation by the end of 2024 to produce the estimated $750 million in net present value product tax credit (PTC) benefits. My direct testimony and associated exhibits summarize the economic analysis that the annual value of PTCs, which originate from the Rock Creek I and Rock Creek II wind projects, starts at $130 million in 2025 and grows to $148 million in 2034.[16] This benefit is conservative, as it does not capture the PTC benefits that third-party developers are passing through to PacifiCorp in their contract pricing.

[14] UM 2059, Staff Report at 8-9 (Oct. 6, 2021).
[15] Dir. Test. Link, at 30-34.
[16] *Id.* at 33.

Delay would have jeopardized these immediate and substantial customer benefits. In fact, at the time, then-current Internal Revenue Service guidance required that the wind facilities dependent upon Gateway South would need to achieve commercial operation by the end of 2025 or risk not qualifying for PTCs altogether. While the 2024 year-end commercial operation date for Gateway South was an economic outcome of our IRP modeling, this timing was further supported to mitigate the risk that project delays for Gateway South or the associated wind facilities would jeopardize the entirety of PTC benefits.

**Q. Despite these significant benefits, has Staff demonstrated that Gateway South presents greater risk compared to a next-best alternative?**

A. No. While Staff points out the risks of constructing Gateway South, Staff does not demonstrate that Gateway South is higher risk compared to a next best alternative. In contrast, the 2021 IRP and the economic analysis in my direct testimony demonstrates that Gateway South was least-cost, least-risk compared to all other alternatives, including the status quo alternative, which would result in increased reliance on the market.

**Q. When facing an imminent capacity deficit, is it reasonable for PacifiCorp to simply do nothing?**

A. No. A do-nothing strategy increases PacifiCorp's reliance on the market, which is subject to price volatility and very real resource adequacy concerns. If the Company had delayed Gateway South, it will have forgone the opportunity for customers to acquire heavily discounted resources in the near term, in exchange for greater reliance on near-term market transactions—which may not be available—and potentially

waiting until after the expiration of PTCs to acquire zero-fuel-cost resources to meet growing energy and capacity needs, particularly in light of what was known about PTC eligibility at the time. There were significant customer risks associated with forgoing the opportunity to procure PTC-eligible resources and there were significant risks associated with greater reliance on higher-cost market transactions that may not even be available—and those risks would be borne by customers.

**Q. Staff concludes that the timing of Gateway South was not justified by the additional wind resources that will be able to interconnect.[17] How do you respond?**

A. First, Staff does not dispute that PacifiCorp's 2021 IRP showed a significant resource need in 2025.

Second, Staff does not dispute the customer benefits of the wind resources that will be able to interconnect because of Gateway South. As explained in the 2019 IRP, the 2020AS RFP, and the 2021 IRP, one of the key benefits of Gateway South is that it will enable PacifiCorp to procure additional wind resources to serve Oregon customers. Those wind resources will materially decrease net power costs (NPC) through zero-variable cost generation, decrease emissions through emission-free generation, consistent with Oregon state energy policy, and provide significant PTC benefits to offset the costs of the wind resources.

Third, Staff appears to discount the fact that the timing of wind resources and construction of Gateway South are linked. Gateway South was originally planned for commercial operation by the end of 2023, to coincide with the expiration of PTCs.

[17] Staff/1400, Pal/15-16.

However, when the PTCs were extended, PacifiCorp reasonably extended the commercial operation date for Gateway South to coincide with the in-service date of bids in the 2020AS RFP that would rely on Gateway South, while providing a risk-mitigating buffer to accommodate potential for construction delays for either Gateway South or the wind facilities, which could jeopardize PTC benefits in their entirety.

**Q. Has Staff proposed removing the wind resources that rely on Gateway South from this case?**

A. No. Staff's position has an underlying inconsistency in that Staff questions the prudence of Gateway South but has not disputed and has accepted all the benefits of the wind resources that rely on Gateway South. This includes the NPC benefits of the wind resources, which were included in PacifiCorp's 2025 Transition Adjustment Mechanism (TAM) filing.

**Q. Has Staff considered the benefits that Gateway South, Segment D.1, and related resources from the 2020AS RFP will provide in terms of emissions reductions required by House Bill 2021 (HB 2021)?**

A. Only in a conclusory manner. While Staff represents that underutilization of Gateway South could result in higher emissions contrary to HB 2021, Staff has not provided any analysis to support these claims.[18]

[18] OPUC Data Response No. 13 ("Staff considered the requirements of House Bill 2021 (2021), PacifiCorp's response to Staff DR 291, and PacifiCorp's Notices of Suspension and Cancellation in OPUC Docket UM 2193. There are no work papers.").

**Q. Even assuming this representation was supported, do you agree with the conclusion?**

A. No. While PacifiCorp did not decide to build Gateway South or Segment D.1, nor select wind resources from the 2020AS RFP, to comply with HB 2021, the additional capacity provided by these transmission lines (and the renewable resources that will interconnect to these lines as a result of the 2020AS RFP) will nonetheless advance the Company's ability to comply with HB 2021. As shown in Figure 4 of my direct testimony, removal of Gateway South and the associated wind projects increases PacifiCorp's reliance on market purchases. Assigning an emissions factor of 0.428 metric tons of carbon dioxide ($CO_2$) equivalent per megawatt-hour of market purchases increases Oregon's share of emissions by 88.6 thousand metric tons in 2025, and by 157.7 thousand metric tons by 2040.

## C. Economic Analysis

**Q. Staff argues that PacifiCorp has not provided a robust cost-benefit analysis supporting Gateway South.[19] Do you agree?**

A. No. Gateway South has been the subject of extensive economic analysis demonstrating significant customer benefits, beginning with the 2019 IRP, which identified a significant resource need and the least-cost, least-risk resource portfolio included Gateway South, which enables procurement of incremental wind resources. Based on the 2019 IRP preferred portfolio, PacifiCorp issued the 2020AS RFP. That RFP examined 141 projects, with 578 proposal variants representing nearly 33,000 MW of capacity. Six final shortlist resources, representing over 1,600 MW of

[19] Staff/1400, Pal/16.

wind generation, require Gateway South to interconnect to PacifiCorp's transmission system. When acknowledging the final shortlist from that RFP, the Commission concluded:

> The analysis showed the portfolio performed well even without market sales. We found this and the other sensitivity analyses to be a meaningful exercise that helped us review the impacts on customers that would result from the acquisition in a future where important characteristics of the energy industry turned out to be different than those reasonably assumed. Based on what we know now, we are comfortable that this RFP shortlist is a reasonable capacity and energy blend, with diversity in contract structures (and therefore rate impact profiles), technology types, and geography.[20]

Relative to Gateway South and Gateway South-dependent bids, the Commission concluded:

> We do agree with Staff that several important factors weigh in favor of PacifiCorp's conclusion that bringing on the Gateway South transmission line is reasonable at this time, including increased regional electric system reliability, delivery of generation resources, and satisfaction of what may indeed be federal legal obligations.[21]

**Q. Did PacifiCorp re-evaluate Gateway South after the 2020AS RFP?**

A. Yes. And as noted in my direct testimony, the transmission line continues to provide benefits for customers. My direct testimony shows:[22]

- Gateway South has a gross benefit of $1.965 billion, which is $128 million higher than the gross costs over the 20-year planning horizon. These benefits include approximately $750 million in PTC benefits, and $1.3 billion in reduced NPC.
- When adjusted for risk, the benefits of Gateway South increase to $260 million.

[20] Order No. 21-437 at 13.
[21] *Id.* at 16.
[22] *E.g.,* Dir. Test. Link, at 28-36.

This is logical, because a system with more zero fuel cost resources and more transmission to move those resources will experience lower costs than a system without those renewable resources and transmission assets, particularly when adverse events occur, like spikes in market prices or outages.

- These benefits are conservative. First, the $260 million customer benefits do not include the value of renewable energy certificates (RECs) generated by the associated wind resources. Customer benefits for all scenarios would improve by approximately $42 million for every dollar assigned to the incremental RECs that will be generated through 2040. Second, the $260 million customer benefits are based on the first 16 years of operation for Gateway South. The benefits, however, will continue to accrue over the 60-year life of Gateway South and the 30-year life of the associated wind resources.
- PacifiCorp again revisited its economic analysis after construction began in June 2022, to account for changing market dynamics.[23] This analysis continued to support the economic benefits of the resources: risk-adjusted customer benefits amounted to $247 million in the medium natural gas and medium $CO_2$ (MM) price-policy scenario.

[23] These included, among others: national tariff policies, global supply-chain challenges, and inflationary pressures required that bidders secure higher prices than originally offered into the 2020AS RFP; account for the Inflation Reduction Act, which potentially increased the value of the PTCs; incorporate impacts from the OTR; and account for greater resource need due to several projects selected in the 2020AS RFP dropping out.

**Q. The net benefits modeled in the 2021 IRP presumed that Gateway South enabled over 1,600 MW of new wind generation selected in the 2020AS RFP to interconnect and provide benefits for Oregon customers, like lower NPC and PTCs. What is the current status of the projects selected in the 2020AS RFP that rely on Gateway South for interconnection?**

A. Of the 1,641 MW of Gateway South-dependent wind generation, only one project (the 280 MW Two Rivers project), is not expected to reach commercial operation in 2025. The remaining wind projects will provide Oregon customer benefits in 2025, as reflected in PacifiCorp's recent TAM filing and in this case.

**Q. Given that fewer projects have interconnected, do you have concerns that this impacts PacifiCorp's economic analyses that supported the transmission lines?**

A. No. As an initial matter, it bears repeating that prudency determinations cannot be applied in hindsight: it would be unreasonable to view PacifiCorp's actions to invest in long-lead resources in terms of actions by third-party developers that PacifiCorp has no control over. What is relevant is what was known and knowable at the time PacifiCorp decided to move forward with the transmission lines.

At that time, PacifiCorp had no reason to believe that the Two Rivers project would not be able to achieve its commercial operation data as specified in its bid in the 2020AS RFP. Moreover, this same project will have an opportunity to bid into future RFPs. The mere fact that this facility will not meet its expected commercial operation date as originally proposed does not mean it is permanently excluded from being built to serve PacifiCorp's customers over the many decades that Gateway South is expected to remain operable.

**Q. How does the cancellation of the 2022AS RFP impact the prudence review of Gateway South?**

A. First, PacifiCorp chose to suspend the 2022AS RFP in September 2023, well after the Company analyzed the transmission lines and commenced construction of Gateway South. As Staff notes, the cancellation of the RFP was not known to PacifiCorp when it commenced construction. Accordingly, cancelling the 2022AS RFP in September 2023 is not relevant to a determination of whether PacifiCorp's multi-year decision-making process to move forward with Gateway South and Segment D.1 that culminated in June of 2022 was reasonable and prudent.

Second, and more importantly, even assuming the cancellation of the RFP was relevant, PacifiCorp would likely increase the value of the generation that is enabled by construction of Gateway South. This is because, as a general matter, the value of generating resources on the system typically decrease when more generating resources are added, and conversely, the value of generating resources is higher if additional resources are not added to the system. So rather than reducing customer benefits, cancelling the 2022AS RFP does the opposite.

**Q. Staff also argues that cancellation of the 2022AS RFP means that Gateway South will be under-utilized, and customer benefits will be lost because interconnection capacity will not be fully utilized.[24] How do you respond?**

A. Staff has not performed any analysis to support this conclusion.[25] That is understandable, because as discussed by Company witness Vail, Gateway South's

[24] Staff/1400, Pal/35.
[25] OPUC Data Response No. 12 ("Staff utilized PacifiCorp's response to Staff DR 291 and PacifiCorp's Notices of Suspension and Cancellation in OPUC Docket UM 2193, and as noted in Staff/1400, Pal/35, lines 1-10. There are no work papers.").

transmission and interconnection capacity are fully subscribed, and have been well before the Company decided to cancel the 2022AS RFP. As a result, there will be no loss of expected customer benefits.

**Q. Can you please describe the two specific issues Staff raised regarding PacifiCorp's economic analysis?**

A. Yes. First, Staff is concerned that PacifiCorp's alternative economic analysis that assumed Gateway South would not be built inappropriately included the cost of a $1.4 billion 230 kV alternative transmission line.[26] Second, Staff claims PacifiCorp did not address the risk of withdrawals of transmission or interconnection service requests.[27] I address Staff's first concern, and Company witness Vail discusses the second.

**Q. Turning to Staff's first issue, why did PacifiCorp include the costs of an alternative transmission line in the scenario that excludes Gateway South?**

A. As described by Company witness Vail, the functional equivalent of the transmission capacity provided by Gateway South is largely unavoidable because the Company has a federal obligation to provide transmission service under an executed agreement for 500 MW point-to-point service. This obligation alone would have required construction of the functional equivalent of Gateway South (but at 230 kV, instead of 500 kV). PacifiCorp's economic analysis reasonably and conservatively assumed that if it did not construct Gateway South and Segment D.1, it would still be required to construct this 230-kV alternative.

[26] Staff/1400, Pal/17.
[27] *Id.*

Recall that what Staff refers to as the "cost-benefit" analysis is based on a calculation that quantifies the difference in costs between a resource portfolio with Gateway South and Segment D.1 and one without. But the "without Gateway South" scenario reasonably included the alternative transmission infrastructure that would have been required if there were no Gateway South or Segment D.1 transmission lines. While Staff claims that PacifiCorp's analysis did not include the full costs of Gateway South, in fact, the analysis simply accounted for the reality that some transmission build out would be required in both the with and without scenarios.

Moreover, even if PacifiCorp were to assume away the executed point-to-point transmission service agreement, the Company is still obligated to provide interconnection service under the 12 executed FERC-jurisdictional agreements, as also described by Company witness Vail. To meet its obligation under these agreements, PacifiCorp would have to construct the functional equivalent of Gateway South and Segment D.1. In this scenario, the net customer benefits of Gateway South increase to $742 million under the MM price-policy scenario.

Company witness Vail also explains that the only way the Company could stop pursuing construction of any transmission facilities in eastern Wyoming and maintain compliance with applicable reliability standards is if the transmission system experienced *no* changes in loads or resources. Therefore, the proper question is when, not if, substantial transmission projects are needed.

**D. Market Reliance**

**Q. Staff claims that increased reliance on near-term market purchases will reduce many of the benefits that Gateway South was intended to provide for Oregon customers.[28] Do you agree?**

A. No. One of the primary benefits of Gateway South and the interconnected wind resources was that the additional generation reduces PacifiCorp's reliance on market purchases at a time when scarcity is becoming more common in the West and resource adequacy is an increasing concern. Without Gateway South, PacifiCorp would lose all of the wind capacity that is contingent on Gateway South and Segment D.1 for interconnection, and would therefore be forced to rely even more on market transactions.

**Q. What is the basis for Staff's claim that increased reliance on market purchases will reduce the benefits of Gateway South?**

A. Staff examined the 2021 IRP, 2023 IRP, and 2023 IRP Update and concluded that because forecast market purchases increased in the 2023 IRP and 2023 IRP Update, the reduced market reliance from Gateway South was not materializing. Staff's analysis, however, does not consider that if Gateway South were removed from the 2023 IRP and 2023 IRP Update forecasts, the reliance on market purchases would increase even more. Therefore, when Staff correctly states that there is a high risk of relying on market purchases, it does not follow that Gateway South is somehow increasing that risk. In fact it is the opposite: Gateway South necessarily decreases

[28] *Id.* at 24.

PacifiCorp's exposure to market purchases, as discussed herein and as I expressly discussed in my direct testimony.[29]

Moreover, there are a myriad of variables that changed between the 2021 IRP, the 2023 IRP, and the 2023 IRP Update. It is not possible to determine that Gateway South has increased PacifiCorp's reliance on market purchases by simply looking at changes in market purchases between and among these plans. And further, information included in the 2023 IRP and the 2023 IRP Update was not known or knowable to PacifiCorp when it decided to build Gateway South and initiated construction of Gateway South in June 2022.

## E. Ozone Transport Rule

**Q. Staff appears to fault PacifiCorp for not incorporating the impact of the OTR when evaluating Gateway South prior to construction.[30] Is that correct?**

A. Not entirely. As an initial matter, the Environmental Protection Agency (EPA) formally proposed the OTR on April 6, 2022, which was roughly three months before construction began. Importantly, however, the rule was not finalized until March 15, 2023, well after construction began. So, there was no final rule to include in PacifiCorp's economic analysis before commencing construction, and any impacts from the OTR should not factor into the Commission's determination of whether PacifiCorp's decision to move forward with Gateway South and Segment D.1 were reasonable and prudent.

[29] Dir. Test. Link, at 32, Figure 4.
[30] Staff/1400, Pal/32.

More importantly, however, it was understood that the proposed OTR would have reduced coal generation at plants located in Utah and Wyoming, and this reduced coal generation would have increased the economic benefits of Gateway South and the interdependent wind resources. Indeed, because OTR effectively added costs to thermal generation, it is akin to the carbon price assumed in PacifiCorp's economic analysis. The Company's modeling demonstrates unequivocally that the benefits of Gateway South increase as the assumed price of carbon increases. The benefits under the high natural gas and high $CO_2$ price scenario were $932 million, or $1,100 million on a risk-adjusted basis. Therefore, while PacifiCorp did not formally incorporate the draft rule in its initial economic analysis, it was fully aware of the rule, understood that it would only increase the benefits of Gateway South, and any impacts that could have been analyzed at the time were already captured in the Company's scenario analysis.

These assumed benefits are confirmed by PacifiCorp's post-construction economic analysis of Gateway South, which did incorporate an estimated impact of the OTR.[31] These analyses reflect the common-sense conclusion above that the OTR in fact increases the benefits that customers would realize from Gateway South and Segment D.1.

**Q. Staff also suggests that PacifiCorp should have reevaluated Gateway South once the OTR was stayed.[32] Do you agree?**

A. No. It is important to clarify the timing of the various EPA and court actions related to

[31] Link Dir. Test., Exh PAC/800 at 36 ("The last of these reviews, prepared in September 2022, reflected updated pricing for all wind resource PPAs dependent upon the Transmission Projects and showed risk-adjusted customer benefits totaling $247 million in the MM price-policy scenario.").
[32] Staff/1400, Pal/33.

the OTR. On January 31, 2023, EPA delayed final action on Wyoming's OTR requirements until December of 2023. This means that PacifiCorp would not have known or could have known the final impact of the rule in Wyoming until 2024. For Utah, it is my understanding that on July 27, 2023, the Tenth Circuit Court of Appeals issued an order that stays the enforcement of the OTR in Utah pending the outcome of the ongoing litigation. This means that any update to the economic analysis of Gateway South would have occurred more than a year after construction began, at which time ceasing construction was impractical.

Just like the initial issuance of the final OTR, the stay of the OTR is not relevant to the Commission's determination of whether PacifiCorp's decision to move forward with both transmission lines were reasonable and prudent.

**Q. Do you have any other concerns with Staff's argument that PacifiCorp should have updated its economic analysis once the OTR was stayed?**

A. Yes. Staff effectively argues that the OTR was the only state or federal regulation that supported PacifiCorp's modeling of a carbon price in its economic analysis.[33] In effect, Staff claims that once the OTR was stayed, the most reasonable economic analysis should have assumed no carbon price of any kind for the entire 20-year study term included in the Gateway South economic analysis. This would not reflect least-cost, least-risk planning principles.

**Q. Why not?**

A. PacifiCorp's price-policy scenarios include varying levels of assumed $CO_2$ costs to reflect the fact that it is more likely than not that some policy will exist that will drive

[33] *Id.*

reduced emissions over the 60-year life of Gateway South. PacifiCorp's modeled $CO_2$ costs were based on a survey of respected third-party industry experts, including PIRA, IHS CERA, and Wood Mackenzie and the Energy Information Administration. The Company also assessed $CO_2$ price assumptions used by peer utilities.

The modeled $CO_2$ costs are not intended to explicitly account for a future tax on $CO_2$ emissions, or specific federal regulations like the OTR. Rather, these are proxy costs that capture the effect of policies that incentivize reduced emissions through various costs, benefits, or other market mechanisms.

**Q. In addition to OTR, what other state or federal policies are reflected in the assumed carbon price included in PacifiCorp's economic analysis of Gateway South?**

A. Most relevant for Oregon is HB 2021, which imposes legally enforceable obligations today that require PacifiCorp to reduce and eventually eliminate carbon emissions from generation used to serve Oregon. Even without the OTR, HB 2021 more than justifies the continued assumption of a carbon price in PacifiCorp's economic analysis for Oregon customers. Indeed, the Commission has specifically recognized that, "PacifiCorp has historically put a long-term price on carbon as a proxy for future regulatory requirements," and "HB 2021 requires a specific carbon budget and a carbon price[.]"[34]

In addition to HB 2021, Oregon Executive Order 20-04, which was signed in March 2020, directs state agencies to take actions to reduce and regulate greenhouse gas emissions, thereby providing additional policy support for an assumed carbon

[34] Order No. 24-073 at 9.

price for Oregon resource planning.[35] Indeed, in May 2021, and in response to Executive Order 20-04, Staff planned to convene a process to consider carbon price modeling and was specifically going to consider removal of the "zero price path."[36]

In other words, while Staff is now apparently arguing that without the OTR PacifiCorp should assume no carbon price in its resource planning, before the OTR was even announced Staff was taking the exact opposite position based on Oregon policies that remain in effect today.

**Q. Does the Commission require PacifiCorp to model future carbon emission compliance scenarios?**

A. Yes. The Commission's IRP Guideline 8, which was adopted in Order No. 08-339, requires consideration of future carbon emission compliance costs in long-term resource planning. Staff's position that the stay of the OTR meant that PacifiCorp should no longer assume any carbon price in its long-term resource planning is entirely at odds with long-standing Oregon policy, and would be unreasonable in the relevant planning environment that informed the decision to construct Gateway South.

## F. Other Concerns

**Q. Staff faults PacifiCorp for not considering the financial impact of litigation over the 2020 Labor Day fires before commencing construction of Gateway South.[37] Is this a fair criticism?**

A. No. PacifiCorp had not identified wildfire liability as of June 2022 when construction

[35] 2021 IRP at 63.
[36] Order No. 21-141, App'x A at 5.
[37] Staff/1400, Pal/34.

began. The *James* verdict was issued nearly a year later and could not have been known or knowable when construction began. It is not relevant to a determination of whether PacifiCorp's decision to move forward with these transmission assets was prudent.

**Q. Staff also claims that Gateway South will not support the closure of coal plants.[38] How do you respond?**

A. First, Gateway South was never intended to drive the closure of coal plants. Rather, Gateway South better positions PacifiCorp to meet various federal and state legal obligations, and relevant to Oregon, will provide access to increasingly lower-emissions generation.

Second, Staff correctly points out that that the expected retirement dates of PacifiCorp's coal units has changed from its 2021 to 2023 IRP, but did so largely as a result of regulatory and market dynamics that have nothing to do with Gateway South.

**Q. Finally, Staff points out that in the 2021 IRP several coal unit retirements were close in time to the in-service date for Gateway South and implies that Gateway South was therefore the reason the coal units were retiring.[39] Is that true?**

A. No. The coal units that were scheduled to retire at the end of 2025 in the 2021 IRP modeling were driven by environmental compliance obligations (Naughton 1 and 2) or are plants where PacifiCorp is a minority owner (Colstrip). Construction of Gateway South was not the reason any of these units were scheduled to close.

[38] *Id.* at 31.
[39] *Id.* at 30-31.

## III. CONCLUSION

**Q. Does this conclude your reply testimony?**

A. Yes.

Docket No. UE 433
Exhibit PAC/2600
Witness: Richard A. Vail

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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# Reply Testimony of Richard A. Vail

**July 2024**

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## ATTACHED EXHIBITS

Exhibit PAC/2601—Follow-on Gateway West without Gateway South Analysis

Confidential Exhibit PAC/2602—Gateway South Analysis Report

Exhibit PAC/2603—New Alternative to Gateway South Analysis

**Q. Are you the same Richard A. Vail who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?**

A. Yes.

## I. PURPOSE AND SUMMARY OF TESTIMONY

**Q. What is the purpose of your testimony in this proceeding?**

A. My testimony responds to the testimony of Public Utility Commission of Oregon (Commission) Staff (Staff) witness Sudeshna Pal and Alliance of Western Energy Consumers (AWEC) witness Chad D. Wilcox, regarding the prudence and cost recovery related to the Company's investment in the Gateway South and Gateway West Segment D.1 (Segment D.1) transmission lines.

**Q. Please summarize your testimony.**

A. Overall, the Company must comply with its federal obligations to maintain a reliable transmission system, as well as provide open access to both transmission and interconnection customers. These requirements—in addition to the demonstrated economic need for these resources as demonstrated by Company witness Rick T. Link—led the Company to move forward with Gateway South and Segment D.1. In doing so, the Company adequately considered alternative scenarios, and concluded that Gateway South and Segment D.1 provided the best solution for our customers and our transmission system. These analyses appropriately considered the risks of transmission or interconnection request withdrawals, and both projects remain on-track, and on-budget.

## II. RESPONSE TO STAFF

**Q. What is the purpose of this section?**

A. I respond to Staff's Gateway South testimony, and specifically: (A) address how the Company's federal requirements to maintain a reliable system, as well as provide open access to its transmission system, obligate the Company to build Gateway South and Segment D.1; (B) address how PacifiCorp adequately considered the risks of transmission or interconnection request withdrawals; (C) further explain why the Company's alternative analyses adequately support the transmission projects in this rate proceeding; and (D) confirm that the projects remain on-track, and on budget.

### A. The Company must comply with its federal obligations

**Q. Staff questions the assumptions used in the Company's Gateway South economic analysis related to the obligation to construct alternative transmission facilities in eastern Wyoming.[1] Please explain the basis for the assumptions that Staff questions.**

A. The Company's economic analysis, addressed by Company Witness Link, reasonably assumed that significant transmission system investments in eastern Wyoming are largely unavoidable given the Company's federally mandated contractual obligations and applicable reliability standards. Therefore, even if the Company had not constructed Gateway South (and Segment D.1), it would still be required to make significant investments in its transmission system and those investments are reasonable to include in the scenario that excludes Gateway South.

[1] Staff/1400, Pal/17.

**Q. How does Gateway South facilitate PacifiCorp's compliance with federal transmission and reliability-related requirements?**

A. PacifiCorp's obligations to operate its transmission system reliably stems from two primary requirements: (1) PacifiCorp's Open Access Transmission Tariff (OATT) that governs the rates, terms, and conditions of transmission and interconnection services; and (2) federal reliability standards.

As detailed below, PacifiCorp's federal OATT study process identified the construction of Gateway South as a prerequisite to reliably providing nearly 2,500 megawatts (MWs) of transmission and interconnection service requests, and as a result, Gateway South was listed in multiple Federal Energy Regulatory Commission (FERC)-jurisdictional executed contracts. In addition, Gateway South facilitates PacifiCorp's compliance with federal reliability standards.

**i. The Transmission Projects are required for 13 FERC-jurisdictional contracts**

*a. PacifiCorp is required to provide open access to its transmission system, and construct transmission system upgrades where necessary*

**Q. Can you provide some background on the creation of PacifiCorp's OATT?**

A. Yes. I am not a lawyer, but I am aware that in 1996, FERC issued a landmark order establishing its open access transmission policies.[2] In short, FERC required that transmission providers offer third parties "open access" to their transmission systems. To implement this requirement, FERC created a pro forma OATT with standardized rates, terms, conditions, processes, and contracts to govern the provision of transmission services. All transmission providers must model their OATT after

[2] *In re Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Pub. Utils.*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996).

FERC's pro forma OATT, and any deviations from the pro forma OATT must be approved by FERC.

**Q. What services does the federal OATT govern?**

A. The OATT primarily governs two basic services: (1) transmission service; and (2) generator interconnection service.

**Q. How are OATT services requested?**

A. OATT services are requested through a FERC-mandated public website called the Open Access Same-Time Information System (OASIS).

**Q. What happens after PacifiCorp receives a request for OATT service?**

A. PacifiCorp must follow OATT processes to perform a series of increasingly more involved engineering studies that evaluate the cost and timing requirements associated with providing the requested service. PacifiCorp must issue reports that summarize the results of its OATT studies, and make those reports publicly available by posting them on OASIS. At the end of the study process, PacifiCorp must tender the requesting party a standardized OATT contract that memorializes the cost and timing requirements identified in the study processes.

**Q. What do you mean by "cost and timing requirements" associated with providing the requested OATT service?**

A. When PacifiCorp receives a request for OATT service, it must evaluate whether it can reliably provide that service on its existing transmission system within the timeframe requested. For example, if the existing transmission system is capable of reliably delivering the requested amount of additional transfer capacity associated with a transmission service request, or reliably interconnecting the requested amount of

generation associated with a generator interconnection request, the OATT studies evaluating that request are likely to state that the service can be granted within the requested timeframe with minimal or no transmission system upgrade costs.

If, and relevant here, the existing transmission system is *not* capable of reliably delivering or reliably interconnecting additional capacity where the OATT service has been requested, PacifiCorp cannot simply reject the service request. Rather, the OATT requires PacifiCorp to identify what transmission system upgrades are needed to accommodate the request, as well as the estimated cost and timing associated with constructing those upgrades. Those upgrades then become requirements identified in the customer's OATT contract.

**Q. How does the OATT require PacifiCorp to construct transmission system upgrades to grant OATT service requests?**

A. The OATT requires PacifiCorp to construct transmission system upgrades to grant OATT requests for transmission service and OATT requests for generator interconnection service. This obligation to construct is found in the OATT's provisions governing: (1) network transmission service; (2) point-to-point transmission service; and (3) generator interconnection service.

**Q. Can you describe the OATT's requirement to construct transmission system upgrades in response to a network transmission service request?**

A. Yes. The OATT's network transmission service provisions require a transmission provider to "plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission

Service over the Transmission Provider's Transmission System" and "endeavor to construct and place into service sufficient transfer capability" to deliver network customer resources to load.[3]

**Q. Can you describe the OATT's requirement to construct transmission system upgrades in response to a point-to-point transmission service request?**

A. Yes. The OATT's point-to-point transmission service provisions require a transmission provider to "use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service" if the transmission provider cannot accommodate the request because of insufficient capability on its system.[4] PacifiCorp's OATT provides as follows:

> In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4.[5]

**Q. Can you describe the OATT's requirement to construct transmission system upgrades in response to a generator interconnection service request?**

A. Yes. Sections 36-52 of PacifiCorp's OATT contain comprehensive rules for interconnecting new generators, including the identification and construction of new network upgrades if they are necessary to grant the request. Importantly, the OATT

[3] PacifiCorp OATT, Section 28.2 (emphasis added).
[4] PacifiCorp OATT, Section 15.4 (emphasis added).
[5] PacifiCorp OATT, Section 13.5 (emphasis added).

process does not give PacifiCorp any authority to refuse an interconnection request simply because it would require new network upgrades.

**Q. Has FERC clarified this OATT requirement?**

A. Yes. While I am not a lawyer, I am aware that in 2003, FERC issued another series of landmark "open access" orders specifically focused on the standardization of the rates, terms, conditions, processes, and contracts under which a transmission provider offers generator interconnection service.[6] FERC established pro forma interconnection provisions to be included in every transmission provider's OATT, and any proposed deviations from the pro forma interconnection provisions must be approved by FERC.

In that interconnection proceeding, FERC explained that its pro forma interconnection services "provide for the construction of Network Upgrades that would allow the Interconnection Customer to flow the output of its Generating Facility onto the Transmission Provider's Transmission System in a safe and reliable manner."[7]

**Q. Does the OATT obligation to construct in response to service requests apply even if the upgrades at issue are previously planned transmission projects?**

A. Yes. The OATT obligation to construct applies to both (1) transmission system upgrades triggered for the first time in response to an OATT request, and (2) previously planned transmission projects identified as necessary to grant a

[6] In 2003, FERC standardized its rules for large generators in the Order No. 2003 proceeding in FERC Docket No. RM02-1. In 2005, FERC standardized its rules for small generators in the Order No. 2006 proceeding in FERC Docket No. RM02-12.

[7] Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, 104 FERC ¶ 61,103 at P 767 (2003) (emphasis added).

subsequent OATT request. By way of background, FERC required transmission providers to amend their OATTs to address transmission planning obligations and processes. For PacifiCorp, Attachment K of its OATT sets forth inter-regional, regional, and local transmission planning processes that are overseen by FERC, the North American Electric Reliability Corporation (NERC), and the Western Electricity Coordinating Council (WECC). As with all provisions in the OATT, PacifiCorp secured FERC approval of the Attachment K provisions and must file any proposed changes with FERC.

**Q. Does this Attachment K process relate to the OATT's obligation to construct transmission system upgrades?**

A. Yes. PacifiCorp's FERC-approved Attachment K makes clear that once a planned transmission project is required to be in-service in order for PacifiCorp to grant an OATT request for point-to-point transmission service or generator interconnection service, PacifiCorp is obligated to construct the planned facilities: "Transmission Provider shall use Point-to-Point Transmission Service usage forecasts and Demand Resources forecasts to determine system usage trends, and such forecasts do not obligate the Transmission Provider to construct facilities until formal requests for either Point-to-Point Transmission Service or Generator Interconnection Service requests are received pursuant to Parts II and IV of the Tariff."[8]

[8] PacifiCorp OATT, Attachment K (emphasis added).

**Q. If PacifiCorp's ability to provide requested OATT service is contingent upon a component of PacifiCorp's long-term transmission plan being in-service, do the OATT studies and OATT contracts make that clear?**

A. Yes. If PacifiCorp cannot reliably provide requested OATT service until a component of PacifiCorp's long-term transmission plan is in place, that upgrade would be listed in the OATT study and OATT agreement as a "Contingent Facility." FERC recently formalized this definition with respect to generator interconnection service, and approved the following definition for inclusion in PacifiCorp's OATT:

> Contingent Facilities shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for Re-Studies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.[9]

**Q. Turning to Gateway South, how do these OATT obligations to construct transmission system upgrades relate to Gateway South?**

A. Gateway South has become a lynchpin in PacifiCorp's ability to provide thousands of megawatts of requests for FERC-jurisdictional OATT generator interconnection service and transmission service. Relevant here, PacifiCorp has executed 12 generation interconnection contract and one transmission service contract that list either Gateway South or Segment D.1, or both, as Contingent Facilities under OATT Section 36. This means that PacifiCorp *cannot provide* the contracted services to 13 parties without constructing Gateway South and Segment D.1.

[9] PacifiCorp OATT § 36.

**Q. Can you provide more detail on how these executed contracts require construction of one or both Transmission Projects?**

A. Yes. I'll first discuss the 500 MW request for point-to-point transmission service, and conclude with a discussion on the 12 executed contracts for generation interconnection services.

*b. 500 MW Point-to-Point Transmission Service*

**Q. Can you describe the transmission service contract obligation dependent on the Transmission Projects?**

A. Yes. PacifiCorp received an OATT request to provide 500 MW of point-to-point transmission service from Aeolus to Mona starting January 1, 2024. In accordance with the OATT process outlined above, PacifiCorp determined it could not deliver an additional 500 MW of power on its existing transmission system, so it performed an OATT system impact study to determine what transmission system upgrades would be required to do so. PacifiCorp's OATT system impact study report states that PacifiCorp's planned Gateway South 500-kilovolt (kV) line from the Aeolus substation to the Clover substation near Mona, Utah must be in place to grant the requested FERC-jurisdictional point-to-point transmission service.[10]

**Q. Why did PacifiCorp conclude that the requested transmission service could not be provided on the existing transmission system?**

A. The short answer is due to reliability concerns. As detailed above, PacifiCorp is "obligated to expand or upgrade its Transmission System" where PacifiCorp

[10] Request No. Q2594 in PacifiCorp's transmission service queue, available at: http://www.oasis.oati.com/ppw/index.html.

determines that it is "not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others . . ."[11]

These circumstances were presented here. After studying its transmission system, PacifiCorp confirmed that the current transmission system could not reliably support the transfer of an additional 500 MW of power from Aeolus to Mona. Under steady-state conditions, increasing transfers between eastern Wyoming (Aeolus) and central Utah (Mona) by 500 MW would result in a voltage collapse of PacifiCorp's east-side transmission system for a minor system contingency in Wyoming or northern Utah. This voltage collapse would violate NERC and WECC reliability standards, degrade the reliability of service to other customers, and negatively impact utilities across the Western Interconnection.

**Q. Why did PacifiCorp identify Gateway South as the "contingent facility" solution to the reliability concern?**

A. The request for 500 MW of point-to-point service coincided with the exact path of the proposed Gateway South line. At the time PacifiCorp studied this transmission service request, Gateway South was estimated to provide an additional 1,700 MW of transfer capability beginning October 31, 2023. Therefore, Gateway South was identified as the contingent facility that would allow PacifiCorp to provide the

[11] PacifiCorp OATT, Section 13.5 (emphasis added).

requested megawatt amount, along the requested path, and in the requested timeframe.

**Q. Could you provide the requested FERC-jurisdictional transmission service with a much smaller (or less expensive) network upgrade, instead of defaulting to PacifiCorp's long-term plan for Gateway South?**

A. No. As a threshold matter, identifying long-term transmission plan components like Gateway South as a contingent facility is consistent with the OATT's directive that transmission providers make efficient use of the estimated capabilities and timelines from the transmission provider's long-term transmission plan. This may not always lead to the identification of transmission system upgrades that create the precise amount of transfer or interconnection capability needed to grant the requested service. That is the case here, where Gateway South creates more transfer capability than is needed to grant the point-to-point request.

Not only was this decision consistent with PacifiCorp's OATT, but it was also reasonable. FERC's policy of allowing contingent facilities to satisfy OATT requests, especially in these circumstances, is far more efficient than requiring the identification and building of new network upgrades. This is because contingent facilities have gone through extensive local, regional, and inter-regional planning coordination spanning multiple years, significant permitting efforts, and multi-year regulatory approval processes before various state and federal agencies. Projects like Gateway South that are already well advanced in these processes have the ability to be more successful, especially when compared to previously unplanned-for network upgrades.

**Q. Did identifying Gateway South as a contingent facility for this specific point-to-point transmission service request result in those efficiencies?**

A. Yes. In fact, the planned Gateway South project is not significantly greater than the transmission system upgrades that would be needed to serve just this isolated request. This conclusion is based on an evaluation PacifiCorp performed in response to stakeholders in a 2019 integrated resource plan proceeding before the Utah Public Service Commission.[12]

In that proceeding, stakeholders asked PacifiCorp to provide information about how its preferred portfolio and system costs might be impacted if Gateway South is assumed to be removed from the preferred portfolio. In response, PacifiCorp explained that, even if Gateway South is not constructed, it is unrealistic to assume that PacifiCorp transmission would not be obligated to construct *any* transmission system upgrades in eastern Wyoming to accommodate FERC-jurisdictional requests for OATT interconnection service and transmission service.[13] Even conservatively ignoring what transmission system upgrades would be required to grant all of the requests it has received for FERC-jurisdictional interconnection and transmission service, and focusing only on the 500 MW point-to-point transmission service request, PacifiCorp estimated it would need to construct, at a minimum, a 230-kV transmission line by the end of 2023, at a cost in excess of $1 billion.[14]

[12] *In re Rocky Mountain Power's 2019 Integrated Resource Plan (IRP),* Docket No. 19-035-02.
[13] Exhibit PAC/2601.
[14] *Id.*at 3.

**Q. So does the OATT obligation to construct apply only to a 230-kV transmission line, rather than a 500-kV transmission line, from Aeolus to Mona?**

A. No. It is estimated that a 230-kV line is required to grant the 500 MW transmission service request, and *only* that request. As I will discuss in more detail in the next section, PacifiCorp has far more than a single request for OATT service in Wyoming, and PacifiCorp could not grant all of the requests with only a 230-kV line.

**Q. Did you execute a FERC-jurisdictional transmission service contract with the entity requesting the 500 MW of point-to-point transmission service?**

A. Yes. PacifiCorp followed the OATT transmission service study process, which concludes when PacifiCorp tenders an OATT pro forma draft transmission service agreement, along with the system impact study report, to the customer.

*c. Interconnection Service Contract Obligations*

**Q. Can you describe the interconnection service contract obligations dependent on Gateway South?**

A. Yes. As of August 2020, PacifiCorp had received approximately 15,000 MW of requests for generator interconnection service in eastern Wyoming.[15] In accordance with PacifiCorp's OATT, PacifiCorp determined it could not reliably accommodate any additional generator interconnections in that area without system upgrades. As a result, PacifiCorp performed and posted to OASIS many system impact studies that identified either one or both of the components of Gateway South and Segment D.1

[15] As of July 2024, PacifiCorp continues to have approximately 3,000 MWs of active requests for generator interconnection service in eastern Wyoming relevant to Gateway South, *above* the projects that are assumed to utilize the entire interconnection capacity created by Gateway South.

as contingent facilities necessary to grant the requested interconnection service. The table below identifies these results at a high level:[16]

| Q# | MW | One or Both Transmission Projects Required |
|---|---|---|
| Q409 | 320 | Gateway South |
| Q713 | 350 | Gateway South, Gateway West Segment D.1 |
| Q719 | 280 | Gateway South, Gateway West Segment D.1 |
| Q783 | 30 | Gateway South, Gateway West Segment D.1 |
| Q784 | 80 | Gateway South, Gateway West Segment D.1 |
| Q785 | 100 | Gateway South, Gateway West Segment D.1 |
| Q789 | 74.9 | Gateway South, Gateway West Segment D.1 |
| Q801 | 80 | Gateway South, Gateway West Segment D.1 |
| Q802 | 50 | Gateway South, Gateway West Segment D.1 |
| Q807 | 75.9 | Gateway South, Gateway West Segment D.1 |
| Q835 | 190 | Gateway South, Gateway West Segment D.1 |
| Q836 | 400 | Gateway South, Gateway West Segment D.1 |

**Q. Why did PacifiCorp conclude that the requested generator interconnections could not be provided on the existing transmission system?**

A. Again, the short answer is due to reliability concerns. As I walked through in more detail above, FERC requires transmission providers to identify the transmission system upgrades that need to be constructed to allow the interconnection customer to "flow the output of its Generating Facility onto the Transmission Provider's Transmission System in a safe and reliable manner."[17] Here, interconnecting additional generation in eastern Wyoming without constructing Gateway South would result in a voltage collapse of PacifiCorp's east-side transmission system for a minor system contingency in Wyoming or northern Utah. This voltage collapse would

[16] The studies provide additional detail on these requirements and are available by cross-referencing the queue numbers in this table with PacifiCorp's interconnection queue, available at: http://www.oasis.oati.com/ppw/index.html.
[17] Order No. 2003, 104 FERC ¶ 61,103, at 767 (2003).

violate NERC and WECC reliability standards, would degrade the reliability of service to other customers, and negatively impact utilities across the Western Interconnection.

**Q. Would you have been able to reliably grant the requested generator interconnections with a much smaller upgrade if you had not defaulted to PacifiCorp's long-term plan for the upgrade solution?**

A. No. In fact, PacifiCorp transmission performed an analysis to test this question.[18] First, PacifiCorp assumed there was no plan to construct Gateway South and Segment D.1. Next, PacifiCorp evaluated what, if any, transmission upgrades would be required to grant the first generator interconnection request that required Gateway South and/or Segment D.1. The Company continued to add projects, and evaluate individual incremental interconnection requirements one at a time, until the Company had added all of the requests that depended on Gateway South and Segment D.1.

The analysis showed that while no single project individually triggered the need for a 500-kV line, because of the cumulative nature of the project-specific studies, the Company would have been required to construct more and more 230-kV and 345-kV transmission lines. In total, the Company could interconnect an estimated 1,441 MW of additional generation resources, which represent 10 interconnection requests, before the next request triggered the need for a 500-kV line to interconnect. To interconnect those 10 projects, however, would cost approximately $1.53 billion.[19] And yet, the Company would have achieved only 814 MW of incremental transfer

[18] Exhibit PAC/2601.
[19] *Id.* at 3.

capability, and as a result PacifiCorp would still have remaining interconnection requests in need of upgrade identification.

By comparison, Gateway South and Segment D.1 were estimated to cost $2.04 billion and provide approximately 1,700 MW of transfer capability and 2,030 MW of interconnection capability.

**Q. What conclusions can you draw from the analysis you performed?**

A. My primary conclusion is that PacifiCorp's identification of Gateway South and Segment D.1 as the upgrade solution to interconnect additional generation in eastern Wyoming did not lead to significantly more upgrades than would have been otherwise required. The analysis demonstrates that the Company likely would have ended up in largely the same spot (i.e., identifying a 500-kV line) with fewer financial, interconnection, transmission, and operational efficiencies. As a result, it was not only consistent with the OATT to identify components of PacifiCorp's long-term transmission plan as contingent facilities in the interconnection studies, but it was also beneficial to customers.

It is also important to remember that this analysis looked at interconnection requests in isolation, without regard to transmission service requests like the 500 MW point-to-point request discussed above. In reality, the OATT requires PacifiCorp to identify the transmission system upgrades necessary to grant *all* of the requests it receives, not just some. Based on PacifiCorp's analysis, it would be impossible to do that without constructing Gateway South and Segment D.1 or their functional equivalent.

**Q. Have you executed interconnection agreements identifying the Transmission Projects as contingent facilities?**

A. Yes. I have executed 12 interconnection agreements that identify Gateway South or Gateway South *and* Segment D.1, as contingent facilities. The counterparties to these executed agreements have, in total, secured contractual rights to all of the estimated 2,030 MW of interconnection capability of Gateway South and Segment D.1. And as noted above, as of July 2024, PacifiCorp continues to have approximately 3,000 MWs of active requests for generator interconnection service in eastern Wyoming relevant to Gateway South, *above* the projects that are assumed to utilize the entire interconnection capacity created by Gateway South.

**ii. The Transmission Projects are required by FERC reliability requirements**

**Q. In addition to the OATT obligations discussed above, are there any other reasons that the construction of significant transmission lines in eastern Wyoming is largely unavoidable?**

A. Yes. Gateway South will enhance the Company's ability to comply with applicable reliability standards imposed by WECC and NERC. As explained in my direct testimony, at the time the Company evaluated reliability issues surrounding Gateway South and Segment D.1 areas, NERC's TPL-001-4 standard required the Company to perform annual reliability assessments to determine whether its transmission system complies with minimum mandatory system performance standards. As a result, Gateway South has been included in the Company's annual TPL-001-4 assessment as part of its short- and long-term plans to dependably meet NERC and WECC reliability requirements for almost a decade. Gateway South and Segment D.1 are

particularly effective in increasing system reliability under the multiple contingency categories of then relevant TPL-001-4 standard, as well as the current and more stringent TPL-001-5 standard.

For example, the 2019 TPL-001-4 planning assessment identified three deficiencies on the existing system that are mitigated by Gateway South and Segment D.1 and four additional deficiencies that are projected to happen by 2029 due to typical system changes and normal load growth.

Further TPL-001-5 issues could arise with other types of system changes as well, such as a significant loss or addition of load. It is because of these conditions that the only way PacifiCorp could stop pursuing construction of any transmission facilities in eastern Wyoming and maintain compliance with the now-relevant TPL-001-5 standard is if the transmission system experienced *no* changes in loads or resources.

Yet those circumstances are not presented here, as demonstrated by the tens of thousands of MWs of requests for interconnection service that the Company has received in the past few years alone, and sustained load growth across PacifiCorp's service territory that is expected to continue for the foreseeable future.

**Q. Can you provide more detail on how these reliability studies support Gateway South and D.1?**

A. Yes. The transmission resources identified in my testimony enhance reliability and alleviate several reliability concerns for Oregon customers caused in part by the addition of the FERC-jurisdictional resources being constructed in eastern Wyoming. Confidential Exhibit PAC/2602 is a study that demonstrates the reliability issues that

are created by the addition of these FERC-jurisdictional resources and resolved by Gateway South and Segment D.1. The reliability concerns arise because the existing transmission system cannot adequately transmit the electricity from these resources without the additional transmission capacity described in my testimony.

Without Gateway South, the addition of the first 320 MW of resources in eastern Wyoming results in thermal overload above the emergency rating of the entire 230-kV transmission system, extending from the Standpipe substation in Carbon County, all the way to the Point of Rocks substation in Sweetwater County under certain system outage conditions.[20] These outages, along with thermal overload, also result in low voltages below acceptable limits around the Echo Springs substation in Carbon County. This 230-kV transmission path, which already has demonstrated reliability concerns, serves several large customers whose service could be potentially impacted in absence of the proposed transmission.

Additionally, Segment D.1 (which includes the rebuilding of the existing Dave Johnston – Amasa – Heward (new substation next to Difficulty) – Shirley Basin 230-kV line, as well as a new 59 mile long Windstar – Shirley Basin 230-kV line) also resolves thermal overloads on the existing transmission system under system normal and outage conditions.[21] It also alleviates low voltage issues under outage conditions and improves the reliability of the transmission system.

[20] Confidential Exhibit PAC/2602, at 7.
[21] *Id.*

**B. PacifiCorp adequately considered the risks of transmission or interconnection request withdrawals**

**Q. Staff claims the Company's economic analysis did not address the risk of withdrawals of transmission or interconnection service requests.[22] How do you respond?**

A. Staff's concern is largely misplaced. It is extremely unlikely that the transmission service request *and* all 12 interconnection requests will be withdrawn. As discussed above, even if the transmission service request is ultimately withdrawn, the Company would still be required to construct the functional equivalent of Gateway South and Segment D.1 to serve the interconnection requests. And of those interconnection requests, none have been withdrawn to date. Indeed, this case specifically includes the interconnection network upgrade costs associated with five of the projects that will interconnect and serve Oregon customers. The current status of the five are as follows:

- Q0409 Boswell Springs Wind generation interconnection network upgrades - Design is complete and major material has arrived. Construction bid was awarded in May 2024 and construction started July 1, 2024. Project is on track for a December 2024 completion.
- Q0713 Cedar Springs IV Wind generation interconnection network upgrades - Design is complete and all material received. Construction bid has been awarded and construction started in June 2024. Project is on track for a December 2024 completion.

[22] Staff/1400, Pal/17.

- Q0785 Anticline Wind generation interconnection network upgrades - Design is complete, material has been ordered and is currently being delivered. Construction bid awarded in June 2024 and construction will start July 30, 2024. Project is on track for a December 2024 completion.
- Q0835 Rock Creek Wind generation interconnection network upgrades - Design is complete and material has been received. Construction started in September 2023 and project is currently forecasted to be complete in October 2024.
- Q0836 Rock Creek Wind 2 generation interconnection network upgrades - Design is complete and all material will be received by November 2024. Construction bid was awarded in May 2024 and construction started the first of July. Project is on track for a December 2024 completion.

Moreover, even if all or a significant number of the specific transmission and interconnection service requests at issue here were to be withdrawn, there remains significant transmission and interconnection demand in eastern Wyoming. Since 2020 when PacifiCorp transitioned to an annual cluster study process for generation interconnection requests, PacifiCorp has received approximately 12,600 MW of requests in its eastern Wyoming region. As stated above, approximately 3,000 MW of those requests are still active and proceeding through various stages of the interconnection study process, all of which require Gateway South and most of which require Segment D.1. In short, for there to be no OATT or reliability standard requirement to construct transmission facilities in eastern Wyoming would require a near total cessation of interest in developing resources in one of the most wind-rich regions of the country.

That scenario is unlikely. And relevant to the current rate case, has not materialized to-date, nor is it expected to occur in the near-term.

**Q. Staff also questions the current status of the 500 MW point-to-point transmission service agreement, and suggests that the contract term for that agreement cannot be met under the current schedule for Gateway South.[23] Do you agree?**

A. No. The transmission service agreement is still in effect, and the Company is obligated to provide the requested service upon completion of Gateway South. This point-to-point transmission service agreement states that service will commence once the construction of the required network upgrades is complete. The underlying study for that contract contains the details of those network upgrade requirements, explaining that the Company's ability to begin providing point-to-point service on the customer's requested start date of January 1, 2024, was based on the estimated timeline of Gateway South at the time the study was performed. The study goes on to explain that any delays in construction of the Gateway facilities beyond January 1, 2024, would result in a delay to the start of the point-to-point agreement. Importantly, the study also explains that if the customer is not prepared to begin taking service once Gateway South is operational, the customer can request to extend commencement of service using the OATT process.

**Q. What is the OATT process that would allow the point-to-point customer to request an extension?**

A. The OATT would allow the customer to request a one-year extension for up to five

[23] Staff/1400, Pal/19.

consecutive years, provided two requirements are met. First, the customer must pay a one-month reservation fee. Second, there can be no other requests for transmission service over that same transmission line. If there are competing requests in the transmission service queue, then the customer must either begin taking service on the original start date, including paying the full OATT rate each month, or forfeit its rights and terminate its contract, allowing the lower-priority requests to take service over the released transmission capacity.

**Q. In this case, have these two requirements been met?**

A. No. Here, there are multiple, lower-priority requests for transmission service on Gateway South, some of which were submitted by the Company. As a result, even in the event the 500 MW point-to-point customer forfeits its transmission rights to PacifiCorp's transmission system, the Company will either maintain the originally projected third-party revenue stream, or it will be able to use the 500 MW of transmission service to move resources to load. The point-to-point customer can also simply terminate its contract rather than seeking an extension of the service commencement date, in which case the result is the same because the released transmission capacity will go to the lower-priority requests in the queue.

**Q. Staff also argues that cancellation of the 2022 RFP means that Gateway South will be under-utilized, and customer benefits will be lost because interconnection capacity will not be fully utilized.[24] How do you respond?**

A. Staff's concern is unfounded. Regarding transmission service, Gateway South is fully subscribed. Approximately 70 percent of the transmission capacity is allocated for

[24] Staff/1400, Pal/35.

network transmission service and the remaining 30 percent is third-party point-to-point service. Regarding interconnection service, the interconnection agreements discussed above remain in effect and legally binding. However, if one of the interconnection customers chooses to terminate its agreement, then the available interconnection capacity will likely be quickly subsumed by the continuing demand for interconnection in eastern Wyoming.

**C. PacifiCorp's alternative analyses adequately support the Transmission Projects**

**Q. Staff claims that there is no evidence that the Company studied potential alternatives to the construction of the 230-kV transmission facilities assumed in the scenario without Gateway South.[25] Is that true?**

A. No. In addition to the studies discussed above, PacifiCorp evaluated three alternative scenarios to address the needs that Gateway South meets.

**Q. Can you explain the first alternative?**

A. Yes. As I explained in my direct testimony, during the Norther Tier Transmission Group (NTTG) 2018–2019 biennial study cycle, Deseret Power, on behalf of itself and four other Utah stakeholders, requested an economic study be performed to evaluate up to two 345-kV transmission lines as a lower-cost alternative to the 500-kV Gateway West and Gateway South lines.

Based on this request, an economic study was performed by the Planning Committee that demonstrated acceptable system performance for the proposed 345-kV lines. However, additional production cost model (PCM) simulations indicated that the 345-kV lines would have lower overall transmission capacity than the

[25] Staff/1400, Pal/18.

planned 500-kV transmission. This capacity limitation would result in increased flows on transmission exiting Wyoming and would force generation to increase in Utah in the PCM simulations, dispatching it without consideration of economics.

In addition to the economic and capacity limitations, securing permits and rights-of-way for the two proposed 345-kV lines could require an additional 12 to 15 years. The Planning Committee also noted that PacifiCorp already secured all rights-of-way and was currently building the Aeolus-to-Anticline 500-kV transmission system in Wyoming, scheduled for energization at that time in 2020. Due to these limitations and because the proposed 345-kV option has no sponsor, the project was not considered in the NTTG Regional Transmission Plan for the 2018–2019 biennial study cycle.

**Q. Can you explain the second alternative?**

A. Yes. PacifiCorp as part of the OATT requirement and 2019 IRP, completed an alternative analysis that included building two 230-kV lines with bundled conductors between Aeolus and Anticline instead of Gateway South as referenced in Exhibit PAC/2603. The study identified that the 230-kV alternative provides significantly less incremental interconnection capability as well as less than half incremental transmission capability with 230-kV alternative.[26]

**Q. Can you explain the third alternative?**

A. Yes. In response to a deficiency noted in Utah Docket No. 19-035-02 Order, which indicated that "PacifiCorp excluded from its modeling a potential alternative transmission expansion case evaluated by NTTG in its 2018-2019 Regional

[26] Exhibit PAC/2603, at 6.

Transmission Plan that demonstrated sufficient merit to warrant PacifiCorp's further study," PacifiCorp performed follow-up analysis that evaluated both performance and cost differences between Gateway South and the proposed 345-kV option presented as an alternative study in NTTG.[27] This analysis also identified significant reduction in interconnection capability with this alternative.[28]

**Q. Was the system performance significantly different between the two configurations?**

A. Yes. Technical studies demonstrated that by replacing the Gateway South Project with 345-kV/230-kV alternative transmission improvements between Aeolus – Anticline – Populus, as illustrated on the figure below, eastern Wyoming wind generation additions would have to be significantly reduced from 1,882 MW to 1,441 MW. For this alternative transmission configuration, transfers from Wyoming – (Idaho) – Utah would be reduced from 1,700 MW to 814 MW due to Path C (Idaho to Utah) transmission path limitations. During the analysis, some Path C 2,250 MW transmission path restrictions specific to the underlying 138-kV system were ignored to achieve a higher rating of 2,414 MW from Idaho to Utah. Under the transfer level evaluated, all transmission paths would be near their path ratings and no thermal/voltage violations would be evident during facility outage conditions. The report identified additional transmission facilities that would be required to support generation additions and transfer level noted above were estimated to cost $1.539 billion to construct.[29]

[27] Exhibit PAC/2601.
[28] *Id.* at 6.
[29] *Id.*

Together, these alternative analyses led the Company to conclude that Gateway West and South were more beneficial.

**D. The Transmission Projects remain on-track, and on budget**

**Q. Staff is concerned that the in-service date for Gateway South will slip beyond the January 1, 2025, rate effective date in this case.[30] Please provide an update on the project schedule.**

A. After almost two years after starting construction, both projects remain on budget. The project budgets, based on contractual provisions, require fixed cash flows that are assessed monthly against confirmed construction progress. Additionally, project risks that could stall or delay completion are identified and mitigated. Key milestones remaining before the in-service date for both projects include:

- Completing all wound core device deliveries by August 2024.
- Completing construction of the 500-kV transmission line by October 2024.
- Completing all communications network additions and upgrades by October 2024.
- Completing the reconstruction of the existing 230-kV transmission line by November 2024.
- Completing construction of the 230-kV Windstar to Shirley Basin line by December 2024.
- Completing commissioning and placing the projects in service in the fourth quarter of 2024.

The transmission projects are on track to achieve each milestone.

[30] Staff/1400, Pal/7.

**Q. In response to concerns over the construction schedule for Gateway South, and other transmission system projects, Staff requests that the Company provide an attestation of a corporate officer that each of the transmission projects has been completed and placed in service before January 1, 2025.[31] Does the Company object to this proposal?**

A. No.

## III. RESPONSE TO AWEC

**Q. Please provide an overview of AWEC's concerns over the recovery of costs associated with Gateway South and Segment D.1.**

A. AWEC's overarching concern is that the development timeline for Gateway South and Segment D.1 has been too long, and the ultimate costs that are sought for recovery here include "expenses related to planning and developing facilities that differ from those being placed in service under the current project plan."[32] AWEC claims that Gateway South and Segment D.1 have changed since planning began in 2007 and the "proposed project cost includes costs incurred for studying, planning, or developing transmission facilities that were eventually abandoned over the course of the project."[33]

**Q. What is the basis for AWEC's concern?**

A. AWEC claims that "initial plan for Gateway Transmission South included a double-circuit 500 kilovolt transmission line from Jim Bridger to Mona, Utah, a single circuit 500 kilovolt (kV) transmission line from Mona, Utah to the Crystal substation

[31] Staff/1400, Pal/9.
[32] AWEC/100, Wilcox/18.
[33] AWEC/100, Wilcox/20.

in Nevada, and Substation expansion at Jim Bridger," while the current configuration of Gateway South includes a "single-circuit 500 kilovolt (kV) transmission line from the Aeolus substation, near Medicine Bow, Wyoming, to the Clover substation, near Mona, Utah, with two intermediate series compensation sites."[34] AWEC has similar arguments surrounding Segment D.1, and the Company's initial plan for transmission upgrades between the Dave Johnston and Jim Bridger generating facilities, and Shirley Basin, and Windstar substations.[35]

**Q. Should certain costs be disallowed because the current configuration of Gateway South and Segment D.1 is different from the initial configurations from 2007, or that certain facilities are abandoned?[36]**

A. No. The configuration of either project has not changed enough to support a claim that the original projects have been abandoned. From a permitting perspective, these facilities remain the same.

**Q. Can you describe the preliminary analysis that informed Gateway South?**

A. Yes. As part of the preliminary work on any transmission project, project alternatives are always evaluated, and Energy Gateway's scope and scale have continued to evolve to meet the needs of PacifiCorp customers and required transmission planning standards and criteria.

By way of background, the Energy Gateway Transmission Expansion Plan is the product of years of ongoing local and regional transmission planning efforts with significant customer and stakeholder involvement. Since Energy Gateway's initial

[34] AWEC/100, Wilcox/20-21.
[35] AWEC/100, Wilcox/21.
[36] AWEC/100, Wilcox/21.

announcement in 2007, this series of projects has continued to be vetted through multiple public transmission planning forums at the local, regional and Western Interconnection level. In accordance with the local planning requirements in PacifiCorp's OATT, Attachment K, PacifiCorp has conducted numerous public meetings on Energy Gateway and transmission planning in general.

PacifiCorp is also a member of NorthernGrid regional planning organization and WECC's Reliability Assessment Committee and was a member of the NTTG regional planning organization for FERC Order 1000 compliance which are now fulfilled by NorthernGrid. These groups continually evaluate PacifiCorp's transmission plan in their efforts to develop and refine the optimal regional and interconnection-wide transmission plans. Additionally, an extensive 18-month stakeholder process on Gateway West and Gateway South was conducted. This stakeholder process was conducted in accordance with WECC Regional Planning Project Review guidelines and FERC OATT planning principles, and was used to establish need, assess benefits to the region, vet alternatives, and eliminate duplication of projects.

As a result of these planning processes, among others, during late 2007 and early 2008, PacifiCorp received in excess of 6,000 MW of requests for incremental transmission service across the Energy Gateway footprint. This supported the need, at that time, for a double-circuit 500-kV line in the area. Yet due to factors beyond the Company's control, these customers withdrew their requests, changes to the load forecasts and firm commitments and partnerships failed to materialize, leading the Company to pursue the current configuration for Gateway South.

These factors are typical of any long-lead transmission project, as the Company refines the needs of its transmission system to respond to current customer interconnection requests and reliability requirements.

**Q. AWEC's adjustment cuts off all costs incurred before 2015.[37] Is that recommendation reasonable?**

A. No. All costs prior to 2015 on Gateway South involved preliminary analysis or permitting costs that would have been incurred regardless of how the line configurations evolved over time. To use one example, it is worth noting that once preliminary work was completed on transmission needs in the area, an internal appropriation request was approved in March 2011, which formally authorized the current project configuration as the single-circuit 500 kV line.

Yet AWEC's cut-off fails to account for this reality of developing long-lead-time resources like Gateway South and Segment D.1. For something on the scale of Gateway South—a several hundred-mile-long line that cross three states—the federal permitting process took 10 years. This is because the Company is required by permitting agencies to ensure enough preliminary analyses and investigations are completed, prior to submission for certification, to determine whether the requested configuration and routes are the best alternatives.

**Q. Can you provide more detail regarding these federal permitting efforts?**

A. Yes. The majority of Gateway South and Segment D.1 in Wyoming will be sited on federal lands. The potential impacts of the Gateway South and Segment D.1 on the surrounding environment and resources have been evaluated as part of the permitting

[37] AWEC/100, Wilcox/24.

process required by the National Environmental Policy Act (NEPA). In 2007, the Company submitted two separate applications for the Gateway South and Segment D.1 to the Bureau of Land Management (BLM) and the United States Forest Service (USFS). For the Segment D.1, the route was analyzed for impacts as an alternative under the Environmental Impact Study (EIS) prepared for the Segment D.1. The draft EIS was issued for a 90-day public comment period in July 2011 and the final EIS issued in April 2013. The BLM and USFS issued their decisions for Segment D.1 in 2013. For Gateway South, the route was analyzed for impacts as an alternative under the EIS for Gateway South Project. The draft EIS was issued for a 90-day public comment period in February 2014 and the final EIS issued in May 2016. For Gateway South, the BLM's decision was issued in 2016, and the USFS's decision in 2017. Throughout the NEPA processes, the Company worked closely with stakeholders including state and federal regulators, local government agencies, private landowners, environmental groups, and elected officials to assess alternative routing.

**Q. AWEC also argues that its recommendation would encourage efficient transmission line development.[38] Do you agree?**

A. Absolutely not. Under AWEC's theory, this would mean that if the Company has started that permitting process in 2015, it would not yet have the federal permit to begin construction of Gateway South. Yet the Company would nonetheless be unable to recover costs beyond this time-limited period. Adopting a framework like AWEC's recommendation would effectively end large-scale transmission development, which cannot occur on the truncated timeline AWEC claims is reasonable.

[38] AWEC/100, Wilcox/24.

It would also prevent utilities from incorporating lessons-learned from these planning studies. Relevant here, the initial Energy Gateway studies allowed PacifiCorp to improve its ability to meet near-term customer needs of moderated load growth and reliability concerns through a limited number of smaller-scale investments that maximize efficient use of the current system. These lessons allowed PacifiCorp to defer, to some degree, the need for larger capital investments like a second 500-kV line from Aeolus – Clover as proposed in the initial plan.

Moreover, adopting an arbitrary cut-off would discourage utilities from thoughtfully reassessing the timing of large-scale transmission line construction out of fear that deferring the in-service date will jeopardize cost recovery. As discussed above, PacifiCorp regularly reassessed the need for Gateway South and Segment D.1 and deferred construction until the lines were economically beneficial for customers. Contrary to incentivizing efficient development, AWEC's adjustment would provide a strong economic incentive to construct projects before they are needed simply to avoid a potential disallowance if development efforts take too long.

Put simply: AWEC's arbitrary cut-off would discourage development of long-lead time projects, like transmission system investments, which are vital to the continued development of emission-free generation necessary to meet Oregon's state energy policies.

## IV. CONCLUSION

**Q. Does this conclude your reply testimony?**

A. Yes.

Docket No. UE 433
Exhibit PAC/2601
Witness: Richard A. Vail

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Richard A. Vail**

**Follow-on Gateway West without Gateway South Analysis**

**July 2024**

**Utah – 2019 IRP Ruling**
**Follow-on Gateway West w/o Gateway South Analysis**

In response to the State of Utah's Order on PacifiCorp's 2019 IRP, PacifiCorp Transmission Planning initiated a follow-on analysis of the NTTG – Economic Study Request (ESR) Gateway West 345 kV alternative to the 500 kV Gateway West (Segment D) and Gateway South (Segment F) projects. The NTTG ESR alternative analysis configuration evaluated two - 345 kV lines from Aeolus – to – Anticline – to – Populus, and no new eastern Wyoming to central Utah transmission line (i.e., no Gateway South [Aeolus – Clover]). For the PacifiCorp follow-on analysis, the NTTG ESR alternative configuration was modified to include the 500 kV Gateway West – D.2 (Aeolus – Bridger/Anticline) project[1] plus one additional 345 kV line between Aeolus and Anticline and two - 345 kV lines between Anticline and Populus. Other 500 kV Energy Gateway Project transmission segments, including Gateway South – Segment F (Aeolus – Clover) and Gateway West – Segment E (Populus – Hemingway), were not included in the analysis.

**Transmission Planning Technical Analysis**

Steps that were followed during the analysis are summarized below.

- A system model that included PacifiCorp's planned Energy Gateway 500 kV transmission plan including (Gateway South) was utilized as the starting point for the alternate analysis. The study used a WECC 2024 Heavy Summer base case that was modified to include 1882 MW of eastern Wyoming wind generation from the PacifiCorp LGI queue, which was scheduled to the Utah – Wasatch Front, to stress both the Aeolus South and Aeolus West transmission paths. This base case included the Gateway West – Subsegment D.2 (Aeolus – Bridger/Anticline) project, the Gateway South (Aeolus – Clover) project and the Gateway West – Subsegment D.1 (Windstar – Shirley Basin) project plus other transmission system improvements (Aeolus – Freezeout 230 kV #2 line and upgraded Bridger 345/230 kV autotransformers[2]) that are necessary to support increased wind generation penetration in eastern Wyoming. No Gateway West (Segment E) project facilities west of Populus were included in the base case.
- From the case above, two different sensitivity cases were developed (see Table 2 summary):
    - **Case 1: High Eastern Wyoming Wind**

      The initial base case was modified to create Sensitivity Case 1 by removing the Gateway South (Aeolus – Clover) project and adding the Aeolus – Anticline - Populus 345 kV transmission facilities illustrated in Figure 1 and defined on Table 1. Other Wyoming transmission facilities (including the D.1 Project) to support increased wind penetration in the eastern part of the state were left in the sensitivity case model. No redispatch of eastern Wyoming generation below the 1882 MW of new generation was made to the sensitivity case. Transmission path flows for Sensitivity Case 1 are noted on Table 3. For this scenario, transmission paths exceed their WECC path ratings.

      Once Scenario Case 1 was developed, a complete set of N-1 and N-2 outages in Wyoming, southeast Idaho and northern Utah were performed and results are provided

[1] The D.2 Project is currently under construction and is scheduled for completion 4Q2020.

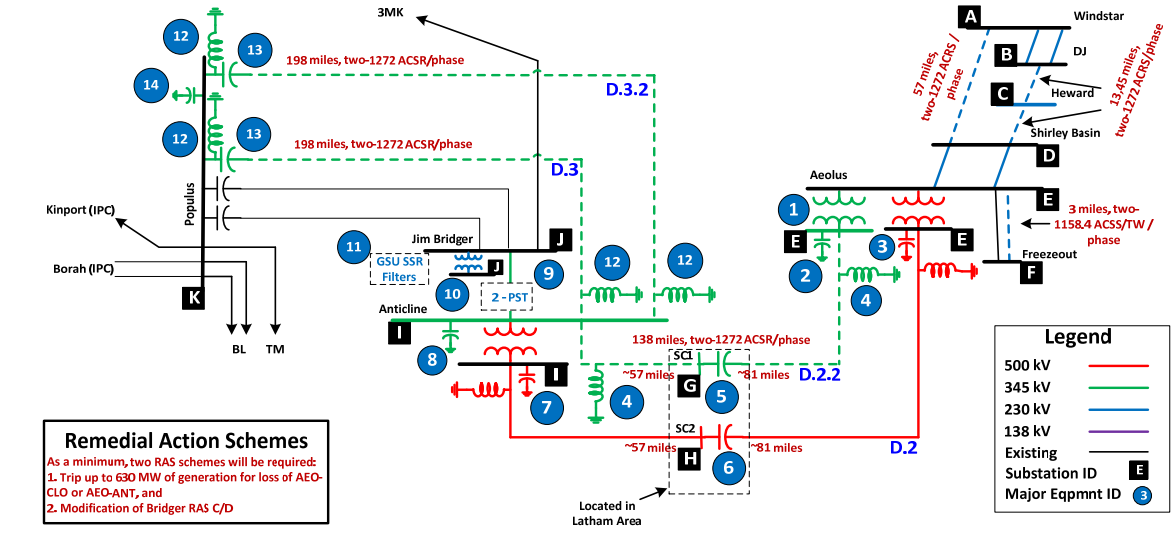
[2] Wyoming transmission system improvements to support higher wind generation penetration in the eastern part of the state call for the Bridger 345 kV #1 and #3 (200 MVA, each) autotransformers will be replace by one – 700 MVA autotransformer. In early 2021, the Bridger 345 kV #2 (200 MVA) autotransformer will be replaced by a 700 MVA autotransformer.

in Table 4. Mitigation for thermal overloads and voltage violations identified are also included in the table.

Case Notes:

1. Dave Johnston generation was assumed at full output and Jim Bridger generation was at reduced levels.
2. The new Wyoming Wind generation represents the generation added to the base case for evaluating the Gateway South project performance in addition to the existing Wind and the wind added following the completion of the Gateway West – Subsegment D.2 project.
3. The new generation resources in Wyoming were dispatched in PacifiCorp LGI queue order to the Utah - Wasatch Front as done in the previous Gateway South case.
4. The Bridger/Anticline West path includes the existing Jim Bridger West path (three - 345 kV lines) and the two new 345 kV lines from Anticline – Populus.
5. The Aeolus West path included both the 500 kV line and the 345 kV line between Aeolus and Anticline, along with the other 230 kV lines which are part of the Aeolus West path.
6. Any transmission path with flows above their path rating or a transmission configuration that has significantly changed from the time they went through the WECC Three-Phase Path Rating Process will be required to repeat the 18-24 month path rating process.

**Figure 1**



## Table 1

### Gateway West (Segment D) - Facility Overview [NTTG Economic Study Anaysis]

Segment D.1 (230 kV), D.2 500 kV, D.2.2 362.25 kV, D.3 and D.3.2 345 kV. Gateway South Excluded
CMQ - 5/26/2020 (RV 2)

**Note: No power flow, dynamic stability or fault duty analysis was performed in developing this list of facilities; therefore, reactive support identified (shunt and series) and breaker/bus sizing will be modified when the overall design is better defined.**

### Gateway West - 230 kV Network Substation Facilities (excluding Aeolus)

| Location | | Major | Substation Equipment | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| ID | Bus Name | Equip | Facility | Voltage Class | Nominal Voltage | # | Rating | Config | Location |
| A | Windstar | | PCB | 245 kV | 230 kV | 1 | 3000 A | 1-1/2 Bus | |
| B | Dave Johnston | | PCB (rebuild bay to 3000 Amp) | 245 kV | 230 kV | 2 | 3000 A | 1-1/2 Bus | |
| C | Heward (near Difficulty) | | PCB (**new substation** - 3000 Amp) | 245 kV | 230 kV | 3 | 3000 A | Ring Bus | |
| D | Shirley Basin (northern lines reterminated in adjacent bays) | | PCB | 245 kV | 230 kV | 1 | 4000 A | 1-1/2 Bus | |
| E | Aeolus - **See Next Section** | | | | | | | | |
| F | Freezeout | | PCB (new 4000 Amp bay) | 245 kV | 230 kV | 2 | 4000 A | 1-1/2 Bus | |

### Gateway West - Segment D.2 (In-Service), D.2.2, D.3 and D.3.2 Substation Facilities

| Location | | Major | Substation Equipment | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| ID | Bus Name | Equip | Facility | Voltage Class | Nominal Voltage | # | Rating | Config | Location |
| E | Aeolus | | PCB (two new 4000 Amp bays) | 245 kV | 230 kV | 4 | 4000 A | 1-1/2 Bus | |
| | **Modifications to the Aeolus RAS will be needed to increase the number of wind farms that possibly could be tripped.** | | PCB (**new 345 kV yard**) | 362.25 kV | 345 kV | 2 | 3000 A | Ring Bus | |
| | | 1 | 1-PH, Transformer (FOA 65/Emergency) | 362.25/245 kV | 345/230 kV | 3 | 533.3/597.3 MVA | Single Θ | Bus to Bus |
| | | 2 | 3-PH, Shunt Capacitor w/PCB (2000 Amp) | 362.25 kV | 345 kV | 1 | 200 MVAr | Three Θ | Bus |
| | | 3 | 3-PH, Shunt Capacitor w/PCB (2000 Amp) | 550 kV | 525 kV | 2 | 200 MVAr | Three Θ | Bus |
| | | 4 | 3-PH, Line Reactor w/PCB (2000 Amp) | 362.25 kV | 345 kV | 1 | 48 MVAr | Three Θ | AEO-ANT 345 Line |
| G | SC1 -345 kV Series Comp Station | 5 | Series Capacitor (2-segment, w/Bypass PCB) | 362.25 kV | 345 kV | 1 | 1800/2160 Amp | 39.19 Ω (3Θ Eq) | AEO-ANT 345 Line |
| H | SC2 - 500 kV Series Comp Station | 6 | Series Capacitor (2-segment, w/Bypass PCB) | 550 kV | 525 kV | 1 | 2300/3105 Amp | 39.25Ω (3Θ Eq) | AEO-ANT 500 Line |
| I | Anticline | | PCB (**new/expanded 345 kV yard**) | 362.25 kV | 345 kV | 9 | 3000 A | 1-1/2 Bus | |
| | | 4 | 3-PH, Line Reactor w/PCB (2000 Amp) | 362.25 kV | 345 kV | 1 | 48 MVAr | Three Θ | AEO-ANT 345 Line |
| | | 7 | 3-PH, Shunt Capacitor w/PCB (2000 Amp) | 550 kV | 525 kV | 2 | 200 MVAr | Three Θ | Bus |
| | | 8 | 3-PH, Shunt Capacitor w/PCB (2000 Amp) | 362.25 kV | 345 kV | 1 | 200 MVAr | Three Θ | Bus |
| | | 9 | Phase Shifting Transformers (PST) | 362.25/362.25 kV | 345/345 kV | 2 | 533.3/597.3 MVA | +40 / -40 Deg Three Θ | Between Anticline 345 kV Bus and Bridger 345 kV Line |
| | | 12 | 3-PH, Line Reactor w/PCB (2000 Amp) | 362.25 kV | 345 kV | 2 | 70 MVAr | Three Θ | ANT-POP 1 & 2 Lines |
| J | Jim Bridger | 10 | Upgrade Bridger 345/230 kV #1 & #3 transformers (200 MVA, each) with a single (700 MVA) bank, including **new/expanded 230 kV yard** | 362.25/245 kV | 345/230 kV | 1 | 700/784 MVA | Three Θ | Bus to Bus |
| | **Jim Bridger RAS would need a complete overhaul as there will be two new parallel lines in the Jim Bridger/Anticline West cut planes.** | 11 | SSR Blocking Filters on Bridger SGU Neutrals | | | 4 | **Per the GE Energy - March 11, 2011 SSR Technical Report Recommendations** | | |
| K | Populus | | PCB (two new 345 kV Bays) | 362.25 kV | 345 kV | 4 | 3000 A | 1-1/2 Bus | |
| | | 12 | 3-PH, Line Reactor w/PCB (2000 Amp) | 362.25 kV | 345 kV | 2 | 70 MVAr | Three Θ | ANT-POP 1 & 2 Lines |
| | | 13 | Series Capacitor (3-segment, w/Bypass PCB) | 362.25 kV | 345 kV | 2 | 1800/2160 Amp | 56.20 Ω (3Θ Eq) | ANT-POP 1& 2 Lines |
| | | 14 | 3-PH, Shunt Capacitor w/PCB (2000 Amp) | 362.25 kV | 345 kV | 2 | 200 MVAr | Three Θ | Bus |

- **Case 2: Reduced Eastern Wyoming Wind**

  Sensitivity Case 2 was developed utilizing the Sensitivity Case 1 transmission configuration; however, the new eastern Wyoming generation resources were significantly reducing from 1882 MW down to 872 MW, in reverse PacifiCorp queue order, until all transmission paths are near their path ratings and no thermal overloads or voltage violations were evident during outage conditions.

  In developing Scenario Case 2, a complete set of N-1 and N-2 outages in Wyoming, southeast Idaho and northern Utah were performed and results are provided in Table 4.

As there were no thermal overload or voltage violations noted for the outage studied, no mitigation will be required.

Case Notes:

1. In developing this sensitivity case, Path C[3] transfers (2250 MW bi-directional path rating) were very important to the analysis due to physical restrictions that exist south of Populus, which will limit significant transmission improvements between Populus – Ben Lomond – Terminal.

This analysis evaluated two different sensitivity cases that were developed based on the assumptions noted in the Table 2:

**Table 2 – Sensitivity Case Generation Dispatch Scenarios**

| Sensitivity Case | Transmission Configuration | Generation Assumptions | Path Flows |
|---|---|---|---|
| Case 1 | 2024 HS Base Case Configuration, remove the Gateway South (Aeolus – Clover) project and add the Aeolus – Anticline - Populus 345 kV transmission facilities identified in Figure 1/Table 1. Other Wyoming transmission facilities (including the D.1 Project) to support wind additions were left in the sensitivity case model. | Eastern Wyoming new generation: 1882 MW<br>This is the same generation level that was modeled in the Gateway South (plus Gateway West D.1 and D.2) base case | Path flows increased above path ratings.<br>**Path Rating studies will be required (18-24 months).**<br>Thermal overload and voltage violations were evident at flow levels modeled. Mitigation facilities are identified in Table 4. |
| Case 2 | Transmission configuraton Identical to Case 1. | Eastern Wyoming new generation significantly reduced to: 872 MW | Path flows within Path Ratings.<br>No thermal overload or voltage violations were evident. |

Study findings identified the generation dispatch and resulting path flows for the two sensitivity cases are noted in Table 3, while general study findings, significant outage, facility overloads and mitigations are summarized in Table 4.

[3] Path C (2250 MW path rating) transfers are limited by 345 kV lines south of Populus reaching an emergency rating for the N-2 outages south of Populus, or an N-2 outage of the 103, 104, 105 – 138 kV lines causing the remaining lines to reach an emergency rating.

**Table 3 – Generation Dispatch and Resulting Path Flows**

| | | Case 1 | Case 2 |
|---|---|---|---|
| New Eastern Wyoming Wind generation | | 1882 MW | 872 MW |
| Aeolus West flows | (2670 MW Limit[4]) | 3465 MW | 2677 MW |
| Bridger West Flows | (2400 MW Limit) | 2246 MW | 1952 MW |
| Bridger/Anticline West flows | (4100 MW Limit[1]) | 4084.6 MW | 3524 MW |
| Path C flows | (2250 MW Limit[5]) | 2694 MW | 2263 MW |

**Table 4 – General Study Findings, Significant Outages, Facility Overloads and Mitigation**

| | Case 1 | Case 2 |
|---|---|---|
| Issues Observed | Yes | None |
| Mitigation Required | Yes | None |

| Outage (● Overloaded Element) | Mitigation | Mitigation |
|---|---|---|
| Loss of D.2 500 kV line with Aeolus RAS<br>• Case 1: Overloads the D.2.2 345 kV series compensation and the conductor on the 345 kV line<br>• Case 2: No violations identified | • Increase the ampacity on the series compensation to be similar to the 500 kV Line<br>• Use a triple bundle conductor for the 345 kV line (3x1272 ACSR Bittern/ phase) | N/A |
| Loss of Aeolus 500/230 kV auto transformer with Aeolus RAS<br>• Case 1: Overloads the Aeolus 345/230 kV auto transformer<br>• Case 2: No violations identified | • Install a second Aeolus 345/230 kV auto transformer | N/A |
| Loss of Aeolus 345/230 kV auto transformer with Aeolus RAS<br>• Case 1: Overloads the Aeolus 500/230 kV auto transformer<br>• Case 2: No violations identified | • Install a second Aeolus 500/230 kV auto transformer. | N/A |

[4] Path Limit was established as part of the WECC Path Rating Process, assuming Gateway West – Segment D and Gateway South – Segment F were in-service. The proposed change in transmission configuration may result in flows exceeding the path limit.

[5] Path C Path Limit was established as part of the WECC Path Rating Process, assuming Gateway West –Segment D is in-service. Physical limitations south of Populus prevent additional transmission facilities to be added.

| | | |
|---|---|---|
| Loss of Rock Springs – Firehole 230 kV line<br>• Case 1: Overloads the Raven – Westvaco – Blacks Fork 230 kV line<br>• Case 2: No violations identified | • Rebuild Raven – Westvaco – Blacks Fork 230 kV line (approximately 10 miles) | N/A |
| N-2 loss of the Wheelon – Treasureton # 1 and # 2 lines<br>• Case 1: Overloads the Wheelon – Treasureton # 3 138 kV Line<br>• Case 2: No violations identified | • Rebuild the 103, 104, 105 138 kV Lines between Wheelon and Treasureton. Rebuilding of the three 138 kV lines approximately 30 miles each | N/A |
| Loss of Threemile Knoll – Goshen 345 kV Line<br>• Case 1: Overloads the Grace – Soda 345 kV Line<br>• Case 2: No violations identified | • Rebuild Grace – Soda – Threemile Knoll 138 kV Line. Approximately 17 miles of 138 kV line | N/A |
| N-2 loss of the Populus – Ben Lomond 345 kV lines<br>• Case 1: Overloads the Populus – Terminal 345 kV line under light load and up to 97% of Rate C in heavy load case<br>• Case 2: No violations identified | • Reconductor the three 345 kV lines between Populus – Terminal to handle higher Path C flows. | N/A |
| N-2 loss of the Populus – Ben Lomond 345 kV lines<br>• Case 1: Low voltages in the Ogden area buses<br>• Case 2: No violations identified | • Additional shunt devices in the Ogden area. | N/A |

**Summary:**

To integrate 1882 MW of additional wind generation in eastern Wyoming, without the Gateway South project, significant transmission facilities would need to be added (see Table 4) in addition to those identified in Figure 1/Table 1. The transmission mitigation identified in Table 4 is not viable due to physical restrictions that currently exist south of Populus, which will limit significant transmission improvements between Populus – Ben Lomond – Terminal. This physical restriction was previously shared with NTTG (see NTTG 2018-2019 Draft Final Regional Transmission Plan, Appendix B).

By replacing the Gateway South Project with a 500 kV/345 kV hybrid transmission system between Aeolus – Anticline – Populus, as identified in Figure 1/Table 1, eastern Wyoming wind generation additions[6] will have to be significantly reduced from 1882 MW to 872 MW for all transmission paths to be near their path ratings and for no thermal overload or voltage violations to be evident during outage conditions.

[6] Generation additions were modeled in LGI queue order. Analysis performed did not take into account existing transmission rights or the TSR queue.

**REDACTED**
Docket No. UE 433
Exhibit PAC/2602
Witness: Richard A. Vail

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**REDACTED**

**Exhibit Accompanying Reply Testimony of Richard A. Vail**

**Gateway South Analysis Report**

**July 2024**

# THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE 433
Exhibit PAC/2603
Witness: Richard A. Vail

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Richard A. Vail**

**New Alternative to Gateway South Analysis**

**July 2024**

**PacifiCorp 2019 Integrated Resource Plan**
**Serial Queue Build Out With**
**No Long-Term Transmission Plan**

To evaluate alternatives to PacifiCorp's Wyoming transmission system master plan, Transmission Planning initiated an analysis of transmission improvements, which would be required to support the Large Generation Interconnection (LGI) queue projects, following the addition of the Energy Vision 2020[1] (EV2020) initiative transmission and generation projects. The alternative analysis evaluated the addition of eastern Wyoming generation in LGI queue order and identified system improvements necessary to interconnect, absent PacifiCorp's transmission master plan. The analysis was performed following an iterative process, where for each iteration an LGI queue project was added, contingencies were run and voltage/thermal violations were identified, and transmission additions to mitigate the violations were then identified and added to the case. This iterative process was repeated until the Gateway South (Aeolus – Clover) Project was identified as being required to interconnect the generation project. At that point, the analysis was suspended and the study findings were documented.

**Analysis Assumptions:**

In performing this analysis, the following study assumptions were made:

- The 2024 Heavy Summer (TPL) configuration Base Case was used for the analysis.
- The Gateway West – Subsegment D.2 (Aeolus – Bridger/Anticline) Project and ancillary 230 kV improvements were assumed to be in-service (4Q2020).
- EV2020 wind generation additions (Ekola Flats, TB Flats and Cedar Springs, totaling 1270 MW) were assumed to be in-service (4Q2020).
- No PacifiCorp long-term transmission master plan facilities beyond the D.2 Project were assumed in the model, e.g.,
    - No Gateway South (Aeolus – Clover) Project, and
    - No Gateway West Subsegment - D.1 (Windstar – Shirley Basin) Project, etc.
- Generation resources in eastern Wyoming were added in the following queue order:
    - Q409 (320 MW),
    - Q713 (350 MW),
    - Q719 (280 MW),
    - Q783 (30 MW),
    - Q784 (80 MW),
    - Q785 (100.5 MW),
    - Q789 (74.9 MW),
    - Q801 (80 MW),
    - Q802 (50 MW), and
    - Q807 (75.9 MW).

    The analysis was suspended after Q807.
- Facility outages were limited to the Wyoming area and Path C (southeast Idaho/northern Utah).
- The analysis focused on thermal/voltage violations that were evaluated per the reliability performance requirements defined in NERC and WECC Planning Standards.
- Jim Bridger generation redispatch was limited[2] to 200 MW plus auxiliary load for each unit to preserve Idaho Power's 800 MW on the Bridger West transmission path.

[1] The EV2020 initiative that was announced by PacifiCorp on April 4, 2017 included repowering PacifiCorp's existing wind fleet in southeast Wyoming, adding three southeast Wyoming wind projects (Ekola Flats, TB Flats and Cedar Springs, totaling 1270 MW) and adding the Gateway West – Subsegment D.2 (Aeolus-Bridger/Anticline) Project and 230 kV network upgrades associated with interconnecting the three wind projects.

[3] Previous D.2 Project and NTTG analysis assumed each Jim Bridger generation unit at 350 MW. The reduced generation level at Jim Bridger (200 MW plus aux load on each unit) was used for this study and all future GWS

- Eastern Wyoming generation addition were redispatched against Hunter/Huntington generation in southern Utah.

**Transmission Planning Technical Analysis**

Steps that were followed during the analysis are summarized below.

- The 2024 Heavy Summer (TPL) configuration base case used for the analysis initially included the Gateway South (Aeolus – Clover) Project, the Gateway West – Subsegment D.1 (Windstar – Shirley Basin) Project and associated LGI queue projects (up to 1882 MW), which were are necessary to load the Gateway South (GWS) transmission path to its 1700 MW rating. In developing the sensitivity case used for this analysis, all future Energy Gateway facilities and associated generation additions after the EV2020 Initiative in-service date (4Q2020) were removed.

  Case Notes:

  1. All assumptions identified above were applied in the analysis.
  2. Path C (Idaho to Utah) transfer capability was assumed to be 2250[3] MW.

- The analysis was performed following an iterative process, where for each iteration an LGI queue project was added (see assumptions), contingencies were run and voltage/thermal violations were identified, and transmission additions to mitigate the violations were then identified and added to the case.
- This iterative process was repeated until Gateway South (Aeolus – Clover) Project was identified as being required to interconnect the generation project.
- At that point, the analysis was suspended and the study findings were documented.

The results of the analysis are summarized on in Attachment A. Additionally, major Transmission facilities identified during the analysis between Aeolus – Bridger/Anticline – Populus are illustrated in Figure 1.

**Summary:**

By replacing the Gateway South Project with 345 kV/230 kV alternative transmission improvements between Aeolus – Anticline – Populus, as illustrated on Figure 1, eastern Wyoming wind generation additions[4] would have to be significantly reduced from 1882 MW[5] to 1441 MW. For this alternative

transfer capability assessment studies and will enable higher levels of eastern Wyoming wind generation to be integrated.

[3] Following that addition of Gateway West – Subsegment D.3 (Anticline – Populus) Project, Path C bi-directional transfer capability will be 2250 MW. At this transfer level, Path C north to south transfers are limited by 345 kV lines south of Populus reaching an emergency rating for the N-2 path outages, or an N-2 outage of the 103, 104, 105 – 138 kV lines causing the remaining lines to reach an emergency rating. Physical transmission corridor restrictions near Willard Bay, Utah have created a "pinch point" that limits future 345 kV transmission expansion south of Populus. This physical restriction was previously shared with the Northern Tier Transmission Group (see NTTG 2018-2019 Draft Final Regional Transmission Plan, Appendix B).

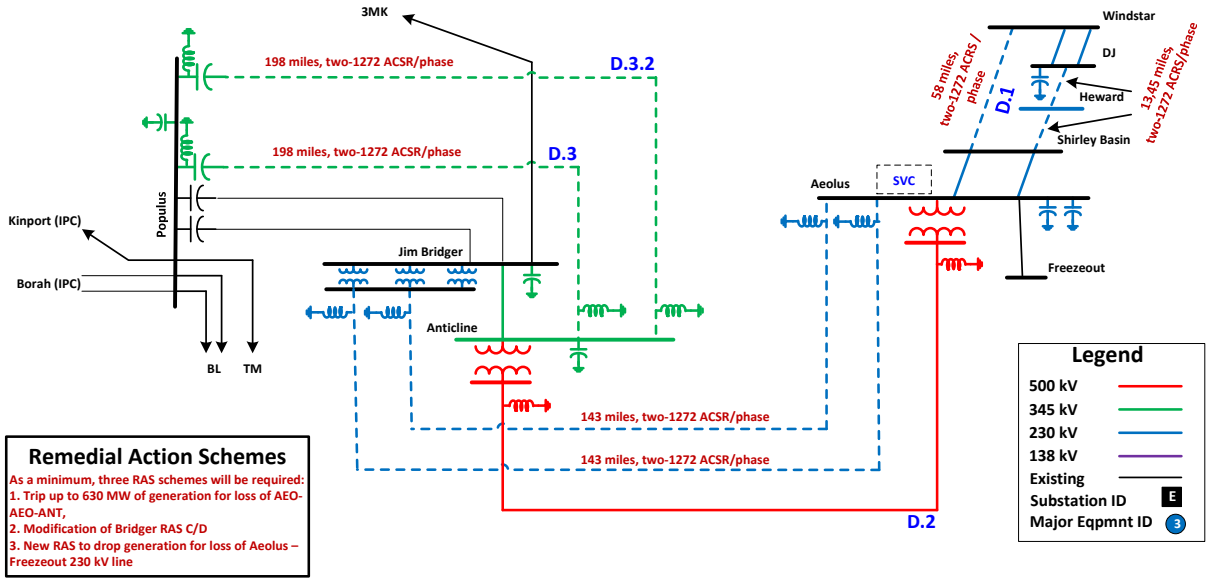
[4] Generation additions were modeled in LGI queue order.

[5] Assumed Gateway South generation interconnection addition level based on serial LGI queue order.

transmission configuration, transfers from Wyoming – (Idaho) – Utah would be reduced from 1700 MW to 814 MW due to Path C (Idaho to Utah) transmission path limitations. During the analysis, some Path C 2250 MW transmission path restriction[4] specific to the underlying 138 kV system were ignored to achieve a higher rating of 2414 MW from Idaho to Utah. Under the transfer level evaluated, all transmission paths would be near their path ratings and no thermal/voltage violations would be evident during facility outage conditions. Transmission facilities identified in Attachment A that would be required to support generation additions and transfer level noted above are estimated to cost $1.539 billion to construct.

Assuming generation is added in LGI queue order, any generation added in eastern Wyoming after Q807 would require the addition of the Gateway South (Aeolus – Clover) Project to interconnect.

**Figure 1: Alternative to Gateway South Overview**



## Attachment A
## Technical Study Results

| Project # | Interconnection Sub/line | Size (MW) | Outage | Thermal Overload | Magnitude (% of Rate C) | Mitigation | Cost ($) | Estimate Tool Worksheet Name |
|---|---|---|---|---|---|---|---|---|
| 409 | Freezeout 230 kV sub | 320 | Aeolus 500/230 kV auto tranformer<br>OR<br>Aeolus - Anticline 500 kV line<br>OR<br>Anticline 500/345 kV autotransformer<br>OR<br>Anticline - Bridger 345 kV line | Platte - Latham 230 kV line | 136 | (1) Expand Jim Bridger 230 kV Substation and convert the 230 kV bus to a breaker and half scheme (new 230 kV yard)<br>(2) A new 230 kV #2 line with bundled 1272 ACSR Bittern Conductor (2x1272) from Aeolus - Jim Bridger (143 miles)<br>(3) Line reactors on the new 230 kV line due to the length of the line | $221,970,178 | Block 1 |
| | | | | Latham - Echo Springs line | 127 | | | |
| | | | | Echo Springs - Bar X line | 126 | | | |
| | | | | Bar X - Bitter Creek 230 kV line | 125 | | | |
| | | | | Bitter Creek - Point of Rocks 230 kV line | 122 | | | |
| | | | Aeolus - Freezeout 230 kV line | Platte - Latham 230 kV Line | 112 | A new RAS that will drop the generation for the loss of the Aeolus - Freezeout 230 kV line | $396,000 | Block 2 |
| | | | | Latham - Echo Springs 230 kV line | 104 | | | |
| | | | | Echo Springs - Bar X line | 104 | | | |
| | | | | Bar X - Bitter Creek 230 kV line | 103 | | | |
| 713 | Yellowcake - Antelope Mine 230 kV line | 350 | None (N-0) | Amasa - Difficulty-Shirley Basin 230 kV | 108 | (1) Build a new substation at Heward next to Difficulty<br>(2) Rebuild Dave Johnston - Amasa - Heward - Shirley Basin 230 kV line with a bundled 1272 ACSR bittern (2x1272) conductor | $83,374,923 | Block 3 |
| | | | None (N-0) | Dave Johnston Unit 3 230/14.5 kV autotransformer | 107 | 100 MVAR shunt at Dave Johnston 230 kV substation | $1,875,500 | Block 4 |
| | | | Amasa - Heward 230 kV line<br>OR<br>Heward - Shirley Basin 230 kV line | Casper - Spence 230 kV line | 104 | (1) Build a new 58 mile long Windstar - Shirley Basin 230 kV line with a bundled 1272 ACSR Bittern (2x1272) conductor | | |
| | | | Laramie River - Ault 230 kV line | Archer - Terry Ranch 230 kV line | 112 | | $77,933,119 | Block 5 |
| | | | Jim Birdger - Populus 345 kV #1 line<br>OR<br>Jim Bridger - Populus 345 kV #2 Line | Jim Bridger - Threemile Knoll 345 kV line | 107 | (1) Expand Populus 345 kV and Anticline 345 kV substation<br>(2) Build a new 198 mile long Anticline - Populus 345 kV #1 line with 50% series compensation<br>(3) Install 1x200 MVAR shunt at Anticline 345 kV bus | | |
| | | | Open ending of the Firehole - Mansface 230 kV line without a fault | Palisades - West Vaco - Raven 230 kV line | 104 | | $339,980,201.00 | Block 6 |
| | | | Jim Bridger 345/230 kV auto tranformer # 2 | Jim Bridger 345/230 kV #1 autotransformer | 110 | Replace Jim Bridger 345/230 kv #1 and # 3 transformer with a single larger 700 MVA transformer. | | |
| | | | | Jim Bridger 345/230 kV #3 autotransformer | 110 | | $7,315,000.00 | Block 7 |
| 719 | Freezeout 230 kV sub | 280 | Aeolus 500/230 kV auto tranformer<br>OR<br>Aeolus - Anticline 500 kV line<br>OR<br>Anticline 500/345 kV autotransformer<br>OR<br>Anticline - Bridger 345 kV line | Non convergence | | (1) Add a new bay to the Jim Bridger 230 kV breaker and half substation<br>(2) A new 230 kV #3 line with bundled 1272 ACSR Bittern Conductor (2x1272) from Aeolus - Jim Bridger (143 miles)<br>(3) Line reactors on the new 230 kV line due to the length of the line<br>(4) Add 2x100 MVAR shunt capacitor bank at Aeolus 230 kV bus | | |
| | | | | Low voltages at Aeolus 230 kV bus | 0.97 PU | | $199,761,178.00 | Block 8 |
| | | | Aeolus - Freezeout 230 kV line | Non convergence | | Ammend the Q0409 RAS that will drop the Q0719 generation for the loss of the Aeolus - Freezeout 230 kV line | $297,000.00 | Block 9 |
| | | | Jim Bridger 345/230 kV # 2 autotransformer | Jim Bridger 345/230 kV # 4 autotranformer | 101 | (1) Expand Jim Bridger 345 kV yard to add a third 345/230 kV (700 MVA) autotransformer | | |
| | | | Jim Bridger 345/230 kV # 4 autotransformer | Jim Bridger 345/230 kV # 2 autotranformer | 101 | | $7,538,300.00 | Block 10 |

Continued next page…

# Attachment A
## Technical Study Results (cont.)

| Project # | Interconnection Sub/line | Size (MW) | Outage | Thermal Overload | Magnitude (% of Rate C) | Mitigation | Cost ($) | Estimate Tool Worksheet Name |
|---|---|---|---|---|---|---|---|---|
| 783 | Bar Nunn 115 kV | 30 | Entire Dave Johnston 230 kV bus outage due to non-redundant bus differential relay | Westhill - Stegall 230 kV line | 101 | Install a redundant bus differential relay at Dave Johnston 230 kV bus. | $396,000.00 | Block 11 |
| 784 | Casper 230 kV | 80 | | No Overloads or Voltage issues observed | | N/A | | |
| 785 | Casper 230 kV | 100.5 | Open ending of the Firehole - Mansface 230 kV line without a fault | Raven - West Vaco - Blacks Fork | 100 | (1) Rebuild 10.3 miles of Raven - West Vaco Blacks Fork 230 kV line with a bundled (2x1272) ACSR Bittern conductor<br>(2) Replace the equipment at Raven, West Vaco and Blacksfork to meet the rating of the rebuilt 230 kV transmission line | $14,265,204.00 | Block 12 |
| | | | Bridger - Threemile Knoll 345 kV line | Non-convergence | | (1) Install a 200 MVAR shunt capacitor bank at Bridger 345 kV bus. | $3,646,500.00 | Block 13 |
| | | | Loss of entire Treasureton 138 kV bus due to non-redundant line relay | Non-convergence | | (1) Install redundant line relays on the 138 kV lines from Treasureton | $1,386,000.00 | Block 14 |
| 789 | Riverton - Thermopolis 230 kV line | 74.9 | Internal breaker fault at Riverton with simultaneous loss of the line to Q0789, two shunt caps at Riverton (1H967) | Low voltage at Riverton 34.5 kV bus | 0.89 PU | Install a shunt a 4 MVAR shunt on Riverton 34.5 kV bus. | $858,000.00 | Block 15 |
| | Path C exceeds 2250 MW | | | | | | | |
| 801 | Bar Nunn 115 kV | 80 | Open ending of the Firehole - Mansface 230 kV line without a fault | Rock Springs - Palisades - Raven 230 kV line | 101 | (1) Rebuild approximately 24.12 miles of RS-PD-RV 230 kV line with a bundled (2 conductor/phase) 1272 ACSR Bittern conductor.<br>(2) Upgrade the required equipment at Rock Springs, Palisades and Raven to meet the line rating | $31,044,032.00 | Block 16 |
| 802 | Bar Nunn 115 kV | 50 | Anticline 500/345 kV auto tranformer with RAS | Low voltages at Bair oil 115 kV , Whiskey Peak 115 kV buses | 0.89 PU | Install a 30 MVAR switched shunt at Mustang 230 kV bus | $1,452,000.00 | Block 17 |
| 807 | Standpipe 230 kV | 75.9 | Simultaneous Outage of Populus- Ben Lomond 345 kV #1 and # 2 lines | Solution not met (Iteration Limit Exceeded) | | (1) Install a 200 MVAR switched shunt at Populus 345 KV | $3,646,500.00 | Block 18 |
| | | | Simultaneous Outage of Treasureton - Wheelon 138 kV # 1 and # 2 lines | Treasureton - Wheelon 138 kV # 3 line | 101 | (1) Rebuild 103, 104, 105 lines from Grace - Treasureton - Wheelon 138 kV lines. Approximately 164 miles of 138 kV line with a 1272 ACSR Bittern conductor. | $164,048,500.00 | Block 19 |
| | | | Failure of the non-redundant line relay at Monument (Breaker 1H2 or | Grace - Soda 138 kV line<br>Emma Park - Upalco PS 138 kv line | 103<br>101 | Install a redundant realy at Monument | $198,000.00 | Block 20 |
| | | | Open ending of the Firehole - Mansface 230 kV line without a fault | Blacksfork - Monument 230 kV line | 100 | (1) Rebuild approximately 6.68 miles of Blacksfork - Monument 230 kV line with a bundled (2 conductor/phase) 1272 ACSR Bittern conductor.<br>(2) Upgrade the required equipment at Blacksfork and Monument to meet the line rating. | $8,990,171.00 | Block 21 |
| | | | Jim Bridger - Threemile Knoll 345 kV line | Solution not met (Iteration Limit Exceeded) | | Build a new 345 kV #2 line from Anticline - Populus with 50% series compensation | $327,529,668.00 | Block 22 |
| | | | Aeolus 500/230 kV auto tranformer<br>OR<br>Aeolus - Anticline 500 kV line<br>OR<br>Anticline 500/345 kV autotransformer<br>OR<br>Anticline - Bridger 345 kV line | Solution not met (Iteration Limit Exceeded) | | Install a -125/+350 MVAR SVC at Aeolus to control the voltage at Aeolus for the loss of the D.2 line segments. | $41,250,000.00 | Block 23 |

$1,539,151,974

Docket No. UE 433
Exhibit PAC/2700
Witness: Timothy J. Hemstreet

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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# Reply Testimony of Timothy J. Hemstreet

**July 2024**

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**Q. Are you the same Timothy J. Hemstreet who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?**

A. Yes.

## I. PURPOSE AND SUMMARY

**Q. What is the purpose of your reply testimony?**

A. I address cost recovery issues related to the Klamath Hydroelectric Settlement Agreement (KHSA) raised by Public Utility Commission of Oregon (Commission) Staff witness Rose Pileggi (Staff), who recommended that the Commission disallow recovery of the costs for the Fall Creek Hatchery recently built by the Company.

**Q. Please summarize your reply testimony.**

A. Contrary to Staff's assumption, the Company has not already recovered capital costs to comply with its hatchery production continuity obligation under Interim Measure 19 of the KHSA.[1] Thus, allowing the Company to recover costs associated with the recent construction of the Fall Creek Hatchery does not result in double recovery of any costs resulting from the KHSA.[2]

Further, recovery of the Company's costs to construct the Fall Creek Hatchery is consistent with ORS 757.374, which allows the Company to recover "undepreciated amounts prudently invested" for amounts "spent by PacifiCorp for settlement of the issues of relicensing or removal of the dam." Because construction of the Fall Creek Hatchery was necessary for PacifiCorp to comply with the KHSA

[1] Staff/1700, Pileggi/4 (indicating Staff may change its recommendation "if it finds that the depreciation schedules failed to include" costs from the Fall Creek Fish hatchery).
[2] *Id.*

(an agreement that the Commission has found is in the public interest), these costs fall within the scope of the statute.

Because Staff does not explain why cost recovery would be inconsistent with this statute, nor argue that these investments were imprudent, the Commission should allow the Company to include these capital costs in Oregon rates.

## II. FALL CREEK HATCHERY COST RECOVERY BACKGROUND

**Q. What is Staff's recommendation with respect to cost recovery for the Fish Creek Hatchery?**

A. Staff recommends that the Commission disallow the capital costs associated with the Fall Creek Hatchery.[3]

**Q. What is the basis of Staff's recommendation?**

A. Staff states that allowing the Company to recover its costs for the Fall Creek Hatchery is inconsistent with the relevant Oregon Revised Statutes related to Klamath dam removal, and would result in double recovery if approved by the Commission.[4]

**Q. Is Staff's analysis correct?**

A. No. The Company has not previously recovered capital costs to comply with its obligations under KHSA Interim Measure 19—which the Fall Creek Hatchery project satisfies—in rate base. Allowing the Company to recover the costs of the Fall Creek Hatchery does not constitute double recovery of these costs.

[3] Staff/1700, Pileggi/4.
[4] *Id.* (citing ORS 757.734, 757.736, and 757.740).

**Q. Staff states that PacifiCorp estimated Klamath settlement costs in 2010 as "approximately $9 million," and that those costs included interim measures, and should have been recovered in the depreciation schedules adopted in the Company's 2010 filing.[5] Do you agree with this assessment?**

A. No. Staff confuses the Company's estimated costs of the KHSA, with recovery of actual costs. In 2010, the Company estimated that capital costs to implement the KHSA between 2010 and 2020 would be approximately $9 million. That $9 million capital cost did not include costs to comply with Interim Measure 19, because in 2010 those costs were assumed to be an operations and maintenance expense, not a capital cost. That assumption turned out to be incorrect, because the best option for ensuring the continued production of an adequate number of fish necessary to meet mitigation goals was to build a new hatchery at Fall Creek.

Regardless whether the Company's assumptions in 2010 about then-current operations and maintenance expenses were correct, when the Commission revised the depreciation schedules for the Klamath River dams as required by ORS 757.734, the depreciation schedules were set to allow the Company's *existing* capital investments to be fully depreciated before 2020 (the target date for dam removal).[6] Reasonably, these depreciation schedules did not consider or estimate the future capital costs that result from KHSA interim measures that were scheduled to go in-service after 2020—like those associated with the new hatchery at Fall Creek.

[5] *Id.* at 4.
[6] *In re PacifiCorp's Klamath Hydroelectric Project Sale-and-Transfer Application,* Docket No. UE 219, Order No. 10-325, at 2-3 (Aug. 18, 2010).

**Q. Has the Company reviewed prior rate proceedings to confirm that costs to comply with Interim Measure 19 have not previously been included in rates, whether as a capital or operating and maintenance expense?**

A. Yes. The Company reviewed its filings from the 2013 rate case,[7] the 2014 rate case,[8] and the 2013 and 2018 depreciation studies,[9] and confirmed that there were no adjustments to operating expenses or relevant depreciation schedules to recover capital costs related to KHSA Interim Measure 19.

**Q. Staff states that cost recovery for the Fall Creek Hatchery would be inconsistent with ORS 757.734. Do you agree?**

A. No. Staff advances no argument for why cost recovery for the Fall Creek Hatchery would be inconsistent with the statute. ORS 757.734 relates to establishing depreciation schedules to allow for the Company's investments in the Klamath River dams to be recovered consistent with the timeframe of dam removal anticipated in the KHSA. Notably, ORS 757.734 requires the Commission to allow the Company to recover "amounts prudently invested" in the Klamath River dams. As detailed in ORS 757.734(2)(d), this includes amounts "spent by PacifiCorp for settlement of the issues of relicensing or removal of the dam." Because construction of the Fall Creek Hatchery was required to comply with the KHSA, and no party has asserted that PacifiCorp's construction of the facility was imprudent (including Staff), I believe the statute requires the Company to be allowed to recover the Oregon-allocated costs of the project.

[7] *In re PacifiCorp's 2013 Rate Case,* Docket No. UE 246, Order No. 13-195 (May 23, 2013).
[8] *In re PacifiCorp's 2014 Rate Case,* Docket No. UE 263, Order No. 13-474 (Dec. 18, 2013).
[9] *In re PacifiCorp's 2013 Depreciation Study,* Docket No. UM 1647, Order No. 13-347 (Sept. 25, 2013); *In re PacifiCorp's 2018 Depreciation Rates,* Docket No. UM 1968, Order No. 20-470 (Dec. 16, 2020).

**Q. Are there other issues the Commission should consider with respect to determining whether cost recovery for the Fall Creek Hatchery should be allowed?**

A. Yes. Aside from the statutory arguments laid out earlier, it should be noted that the Commission has extensively reviewed the KHSA, and found this landmark settlement agreement to be in the public interest.[10] Given the long record before the Commission on this matter over the past 15 years, it would be inconsistent with that record to not allow the Company to recover its prudently incurred costs of implementing the KHSA.

## III. CONCLUSION

**Q. What is your recommendation?**

A. I recommend that the Commission allow the Company to recover the full Oregon-allocated costs of the Fall Creek Hatchery project, because the Company has not previously recovered these costs resulting from the KHSA, and because recovery is consistent with the relevant statutes related to Klamath dam removal.

**Q. Does this conclude your reply testimony?**

A. Yes.

[10] *In re PacifiCorp's Klamath Hydroelectric Project Sale-and-Transfer Application,* Docket No. UE 219, Order No. 21-242, Appendix A, at 12-14. (Aug. 18, 2010).

Docket No. UE 433
Exhibit PAC/2800
Witness: Brad D. Richards

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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# Reply Testimony of Brad D. Richards

**July 2024**

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**Q. Are you the same Brad D. Richards who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?**

A. Yes.

## I. PURPOSE AND SUMMARY

**Q. What is the purpose of your testimony in this case?**

A. My testimony provides clarification regarding the operations and maintenance (O&M) expenses for Jim Bridger Units 1 & 2 and addresses why the Public Utility Commission of Oregon (Commission) should reject the approximately $9 million adjustment proposed in the testimony of Commission Staff witness Mitchell Moore (Staff).[1]

**Q. What O&M expenses were provided for Jim Bridger Units 1 & 2?**

A. The O&M expenses the Company provided for Jim Bridger are the total plant costs for all four units and are not representative of only Units 1 & 2. Please refer to Company witness Sherona L. Cheung's response testimony for additional information regarding the O&M calculations.

**Q. Why are the O&M expenses provided at the plant level?**

A. Units within the same plant share certain resources and common equipment. The Jim Bridger plant has traditionally accounted for common expenses at the plant level, rather than assigning specific common costs to individual units.

[1] Staff/1200, Moore/8.

**Q. Did the Company make an adjustment to the total plant O&M estimates to account for the conversions of Unit 1 & 2 to natural gas?**

A. Yes. The total plant O&M estimates were reduced from $60.9 million to $50.1 million. This reduction is attributed to reduced costs related to ash and coal handling, startup fuel, pollution control and labor on Units 1 & 2.

**Q. Can you provide an approximate breakdown of the costs between the units at Jim Bridger Plant?**

A. As the $10.9 million total-Company reduction is attributable to the conversion of only Units 1 & 2, the reduction would be applied to each of those units. An allocation of the $50.1 million total plant expense is estimated to be $10 million for each of Units 1 & 2, and $15 million for each of Units 3 & 4.

**Q. Is it appropriate to estimate plant O&M expenses for Jim Bridger Unit 1 & 2 based on an average calculation of other PacifiCorp gas-fired facilities?**

A. No. Jim Bridger Units 1 & 2 are large gas fired boilers with remarkably different technology, vintage, and size than the other PacifiCorp gas plants (excluding Naughton Unit 3). Chehalis, Currant Creek, Hermiston, and Lake Side are all modern combined cycle power plants, utilizing combustion turbines and steam turbines in series to generate electricity more efficiently than units built in the 1970's. Additionally, the plants are designed for minimum staffing, as a significant portion of the process is automated with remotely operated equipment that can be controlled by computer. The other PacifiCorp gas-fired facility, Gadsby, has both relatively small gas fired boiler and separately, peaking combustion turbines. The six units at Gadsby have a combined generating capacity of 358 megawatts, roughly equivalent to the

capacity of each Jim Bridger unit (PacifiCorp share), and has 2023 historical O&M expense of $9.7 million. While similar to the estimate provided for Units 1 & 2 allocation, the majority of the O&M expense for that plant are associated with the gas-fired boilers, not the peaking combustion turbines.

## II. CONCLUSION

**Q. What is your recommendation regarding the revenue requirement adjustment proposed by Staff?**

A. I recommend that the Commission reject the proposed adjustment on the basis that it was calculated based on the operating characteristics of gas plants that do not have comparable operational requirements. PacifiCorp did revise its calculation of O&M at the Jim Bridger facility to account for the gas conversion and that calculation is consistent with similarly operated gas plants like Gadsby.

**Q. Does this conclude your reply testimony?**

A. Yes.

Docket No. UE 433
Exhibit PAC/2900
Witness: Allen L. Berreth

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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# Reply Testimony of Allen L. Berreth

**July 2024**

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**Q. Are you the same Allen Berreth that filed direct testimony on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?**

A. Yes.

## I. PURPOSE AND SUMMARY

**Q. What is the purpose of your reply testimony in this case?**

A. My reply testimony responds to the opening testimony of Julie Dyck and Luz Mondragon on behalf of the Public Utility Commission of Oregon (Commission) Staff (Staff).

**Q. Please summarize your reply testimony.**

A. My reply testimony recommends that the Commission reject Staff's adjustments related to the Juniper Ridge Bend Service Center and the Company's purchase of vehicles. Staff's adjustment related to the Juniper Ridge Bend Service Center does not accurately state the amount of outstanding work and implies imprudence when the Company has been appropriately and prudently managing this project. Staff's adjustment related to vehicles does not accurately reflect the drop in vehicle acquisitions that has occurred previously, nor does it take into account the pace of activity and the vehicles to support those activities. Finally, I discuss the Company's efforts to control the rising costs of vegetation management programs.

## II. RESPONSE TO STAFF'S RECOMMENDATIONS AND ADJUSTMENTS

### A. Juniper Ridge Bend Service Center

**Q. Please provide a brief overview of the new Juniper Ridge Bend Service Center that is being constructed.**

A. The Juniper Ridge Bend Service Center will be used primarily by the Company field employees that provide operational support to the surrounding communities. Operational

support includes maintenance, operations, construction of the transmission, substation, and distribution electrical network. This new site will consolidate the three Bend-area operating centers (the leased Bend Service Center and Bend Metering Office, and the owned Bend Substation Ops) into one location and resolve end-of-lease risks for the current Bend Service Center and Bend Metering Office.

**Q. Why is the Company consolidating all these operations and will it result in lower costs for Oregon customers?**

A. Yes, the consolidated operational center creates increased collaboration, facility efficiencies (e.g., building maintenance, consolidated storage, etc.) and makes use of the previously unused Company-owned Juniper Ridge property. Consolidating multiple leased facilities into one Company-owned location reduces annual rent expense and eliminates future lease increase exposure.

**Q. Can you provide a timeline for the Company's permitting and construction process?**

A. Yes, Table 1 below details the project timeline dates.

**Table 1**

| Construction/Permitting Timeline | Date |
|---|---|
| Design and Engineering | 4/30/2022 |
| Permits submitted | 5/17/2022 |
| Mass excavation started | 8/29/2022 |
| General Contractor Awarded | 11/1/2022 |
| Building permit (Phase 1) issued | 2/22/2023 |
| Construction Start | 3/1/2023 |
| Building permit (Phase 2) issued | 6/23/2023 |
| Building permit (Phase 3) issued | 8/23/2023 |
| PEMB Mechanic building final | 10/4/2024 |
| Administration building final | 11/5/2024 |
| PEMB Warehouse building final | 11/1/2024 |
| PEMB Truck Bay building final | 11/1/2024 |
| Project close out | 11/30/2024 |

**Q. Can you identify the amounts that have been spent to date?**

A. Yes, Table 2 below identifies the amount that has been through June 2024.

**Table 2**

| **Spend to Date** | **Through June 2024** |
|---|---|
| General Contractor | $ 26,228,749 |
| Design & Consultants | $ 1,069,960 |
| Other Contractors | $ 2,002,669 |
| IT & Project Management | $ 654,682 |
| Permit and Licensing | $ 547,842 |
| Overheads & Interest | $ 3,472,184 |
| **Total** | **$ 33,976,088** |

**Q. Staff is recommending a downward adjustment of $5.7 million for Juniper Ridge Bend Service Center.[1] Is this adjustment appropriate?**

A. No, this adjustment is an inappropriate disallowance of costs that have been prudently incurred to build a necessary new service center for maintaining distribution facilities that serve Oregon customers.

**Q. In their recommendation, "Staff believes that it is unreasonable to expect that 35 percent of the [p]roject costs would occur 10 months prior to [the] project being placed in service, given that it was started in 2019."[2] Can you explain why such a large percentage of the project costs would occur towards the end of the project?**

A. In years 2019 through 2022 Juniper Ridge was in the 'design and programming' phases of the project in which approximately $3.1 million was spent. Construction activities did not start in earnest until first quarter of 2023 as shown in the timeline table above. The main construction phase of the project is a 22-month period, and the final six months has

[1] Staff/800, Dyck/22.
[2] Staff/800, Dyck/22.

many trades and activities occurring that are almost entirely committed and scheduled as the company has shown.

**Q. Staff claims to have reviewed the outstanding costs and "does not expect that [the Company] will spend the remaining $14.2 million in estimated project budget costs."[3]**

A. As shown in Table 2 above, $33,976,088 has already been spent on the project through June 2024, therefore $7.7 million is the remaining cost on the project, not $14.2 million as Staff has indicated. Except for small amounts to complete the project, all the work has been awarded and scheduled.

**Q. Staff additionally claims that they do "not find the Company's justification for outstanding spending convincing."[4] How do you respond?**

A. The Company is unclear upon what basis that Staff finds these justifications unconvincing. The Company has been reviewing the costs and pace of activity necessary to finish the project. The general contractor is experienced and is in control of the overall project schedule. This schedule includes owner responsible work such as furniture, audio visual, etc. that is not part of the general contractor's scope. The Company is relying on the experience of the general contractor to complete the work as scheduled and is confident the costs will be incurred as shown in the schedule.

**Q. Is it common in construction projects like this for a large portion of the costs to be incurred towards the end of the project?**

A. The remaining project activities and costs are not unusual and are expected for a project of this size and nature. The Company has a very experienced general contractor that

[3] Staff/800, Dyck/22.
[4] Staff/800, Dyck/23.

developed and is executing the project on schedule to the Company's satisfaction. In addition to the remaining contracted cost with our general contractor, the Company's outstanding costs are associated with low voltage construction, security, audio visual, and design contractors and consultants. Other Company activities that will be completed over the next few months are paving, furniture installation, building management systems, electric vehicle chargers, signage, pole and transformer exterior racking, information technology installation, and move in of employees, equipment, and materials.

**Q. Staff additionally has concerns about the fact that the estimates that were provided in the original project budget were lower than the actual costs that have been incurred and projected in this rate case.[5] Can you explain how the budget forecasts could vary significantly from the actual and projected costs included in this rate case?**

A. The project cost increase from $37.6 million in July of 2022 to $41.6 million today was primarily due to inflation and permitting delays and project changes. It is not unusual for an initial project estimate to be below actual costs especially as inflation was increasing in this period. The construction industry was not spared from cost increases in raw materials, furnished goods and labor. Permitting delays also impacted the contractor's ability to work efficiently through the three phases of this project which led to increased overhead cost due to impacted schedule. Change orders typical of this type of project also contributed to increased cost. In light of these factors and economic conditions, the current projected change of 10.6 percent when compared to the initial estimate is reasonable.

[5] Staff/800, Dyck/22.

**Q. What caused the delays in permitting?**

A. While PacifiCorp and its contractors sought the appropriate permits on time, there were delays in receiving the permits from city and county authorities. These delays were not caused by design changes, but rather longer wait times for the permitting to occur.

**Q. Staff additionally suspects that design modifications increased permitting costs and then implies that those costs would not have been incurred if the Company was acting prudently.[6] Is Staff conflating multiple unrelated events to draw a conclusion that the Company was imprudent?**

A. Yes. Currently the Company has paid $783,523 to the City of Bend for permitting and is reserving $100,000 in the budget for remaining inspections, design review, and final occupancy permits. The cost incurred to date is for standard fees, permits, and system development charges (SDC) only, per the City of Bend's development department fee structure. Most of the fees are for the SDC fees which are based on type of building, occupancy classification and square footage of the buildings. There were no additional fees incurred or permitting delays due to design changes.

**Q. Staff is additionally concerned that the Juniper Ridge Bend Service Center should not be situs assigned to Oregon customers because it provides some training facilities for employees Company-wide. How do you respond?**

A. The Juniper Ridge Bend Service Center is situs assigned to Oregon consistent with the 2020 Inter-Jurisdictional Cost Allocation Protocol because it primarily supports distribution facilities across the state of Oregon. This is appropriate and consistent with how the Company has always allocated costs. There will be an area in the building that

[6] Staff/800, Dyck/23.

will be reserved for training of employees, and it is expected that there will be some employees from outside the state who will be trained there. This will be a small percentage of the trainees. The training portion of the building is approximately 4 percent of the space and an even smaller fraction of the cost when the yard is included. There is no cost for the project related to training employees from outside Oregon. The Company would not have reduced the size of the training room if non-Oregon employees would have been excluded, and it will be used by Oregon employees the majority of the time. The training rooms are not spacious, and cross-training provides a benefit to Oregon employees to interact with other highly trained trades people from other states. As noted above, the predominant function of this facility is to serve distribution facilities in Oregon.

**Q. What is your recommendation to the Commission on the Juniper Ridge Bend Service Center?**

A. I recommend the Commission reject Staff's adjustments.

**B. PacifiCorp's Purchase of New Vehicles**

**Q. Can you explain how PacifiCorp determines when to purchase new and replacement vehicles?**

A. PacifiCorp evaluates existing vehicles for replacement based upon several metrics, including mileage driven, engine hours, cost of preventive and corrective maintenance, age of vehicle, and safety of vehicle operation. PacifiCorp uses the metrics to maintain a cost and operationally efficient fleet while deciding which vehicles to replace and which to redeploy within the fleet or within a critical spare vehicle pool. PacifiCorp also benchmarks with industry peers on these metrics and processes.

**Q. Can you provide additional detail on how PacifiCorp purchases vehicles in a manner that results in the lowest costs for customers while maintaining safety and reliability?**

A. Once PacifiCorp determines which vehicles require replacement based upon the cost of maintaining and operating the equipment, and the efficiency of operation and safety of vehicle, PacifiCorp utilizes vendors that compete through a Request for Proposal process to establish the least cost vendor for executing purchases. Additionally, PacifiCorp utilizes consistent design standards for medium and heavy-duty fleet that are aimed at limiting customizations that increase cost for manufacturing and vendor services.

**Q. Staff proposed a $3.2 million adjustment because they question "the prudency of purchasing 38 new vehicles at the same time as the Company fleet requires 65 replacement vehicles."[7] Does Staff's analysis incorrectly characterize the Company's purchase of new vehicles?**

A. Yes, PacifiCorp's purchase of 38 new vehicles in addition to 65 replacement vehicles is prudent to the Company's business needs based upon several years of lower vehicle replacements and lower internal operating workforce prior to this regulatory period. PacifiCorp held capital vehicle replacement costs at lower levels between 2015 and 2019 as attrition in headcount in the field classifications occurred as a result of lower work volumes due to lower new connect and replacements. This allowed the Company to reallocate the existing fleet and lower the volume of replacement purchases. Since that time, new connect volumes, asset resiliency projects, asset inspection and asset correction work have all increased, driving increased field headcount, especially in 2022 and 2023.

[7] Staff/1100, Mondragon/16-17.

The increased activity requires new vehicle purchases to ensure there were enough vehicles, trailers and off-road equipment to respond to the increase in daily work activities, as well as to the increase in activity associated with new wildfire policies and escalating wildfire and storm events. In addition to the business changes, supply chain constraints in 2020 and 2021 deferred receipt of vehicles that had already been ordered.

**Q. Is the Company's purchase of these vehicles necessary and prudent to maintain safe and reliable service for customers?**

A. Yes, as described above these vehicle purchases are not only prudent but necessary to ensure that personnel can complete scheduled daily work, but also to ensure wildfire policy and program response, and to ensure the proper types of vehicles for storm and wildfire event response.

**Q. What is your recommendation to the Commission on this adjustment?**

A. I recommend that the Commission reject this adjustment.

**C. Wildfire Mitigation and Vegetation Management Expense**

**Q. Staff raises a concern that they "would like to see the Company work towards more cost control and a future where increases in annual costs to the Routine Vegetation Management program are reduced. Climate change and its effects on PacifiCorp's service area will continue to pose challenges, and innovation in cost effectiveness is necessary."[8] Can you explain what steps the Company is taking to manage vegetation management costs?**

A. PacifiCorp agrees with the importance of cost controls, while acknowledging the impacts of climate change on implementation of its vegetation management program. PacifiCorp

[8] Staff/1100, Mondragon/30.

has increased its staff at the management and forester levels. This allows for increased scrutiny in the implementation of the program and increased oversight and management of its vegetation management contractors. PacifiCorp is also working with its vendor to upgrade the Company's vegetation management work management software. This upgrade is anticipated to increase efficiencies in work issuance and tracking; including tracking of trees treated with tree growth regulator to better inform pre-listing efforts. In addition, PacifiCorp will investigate and seek to leverage appropriate technology such as use of remote sensing tools to improve efficiency and targeted maintenance.

**Q. Are there countervailing trends or issues that are outside the Company's control that could lead to increased vegetation management expense in the future?**

A. Yes. As Staff has pointed out, climate change, which includes drought and local or regional changes in climate, may result in conditions that influence strategies and implementation of PacifiCorp's vegetation management program. For example, southern Oregon, is experiencing an increase in tree mortality (Douglas-fir). This may result in an increase of more costly tree removals in order to mitigate hazards, and provide safe, reliable power. Related to this, as we continue to experience changes in regional and local climate, there is the potential for additional restrictions and work shutdowns due to warmer and drier weather conditions in forested areas, which may result in additional challenges and inefficiencies in executing the work. Changes in jurisdictional permitting requirements could also lead to inefficiencies and increased costs in the form of fees and application costs. In addition, labor costs associated with vegetation management are expected to continue to increase. These factors may result in increased costs that offset the benefits realized through additional cost control measures.

**Q. Does this conclude your reply testimony?**

A. Yes.

**REDACTED**
Docket No. UE 433
Exhibit PAC/3000
Witness: James C. Owen

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**REDACTED**

**Reply Testimony of James C. Owen**

**July 2024**

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## ATTACHED EXHIBITS

Confidential Exhibit PAC/3001—PacifiCorp Coal Inventory Policies and Procedures

Confidential Exhibit PAC/3002—Coal Inventory Study for PacifiCorp Coal-Fired Power Plants in Wyoming and Utah

## I. INTRODUCTION AND QUALIFICATIONS

**Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company).**

A. My name is James C. Owen. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah 84116. My title is Vice President of Environmental, Fuels, and Mining.

**Q. Briefly describe your education and professional experience.**

A. I have a Bachelor of Science Degree in Mining Engineering, a Master of Business Administration Degree, and a Juris Doctor Degree, all from the University of Utah. I joined the Utah Department of Natural Resources – Division of Oil, Gas and Mining in November 2008, and held positions of increasing responsibility within the agency, including responsibilities for environmental permitting, enforcement of environmental compliance, engineering design, oversight of mine reclamation bonding, environmental program management, and legislative and policy management. I joined PacifiCorp as Director of Environmental in February 2018. I have assumed positions of increasing responsibility since that time and currently serve as Vice President of Environmental, Fuels, and Mining. My current responsibilities encompass strategic planning, stakeholder engagement, regulatory support, support of major generation resource additions, direct oversight of fueling strategy, management of mining operations, and direct oversight of major environmental compliance projects.

**Q. Have you testified in previous regulatory proceedings?**

A. Yes. I have previously provided testimony on behalf of the Company in proceedings

before the Public Utility Commission of Oregon (Commission) and the public utility commissions in California, Idaho, Utah, and Wyoming.

## II. PURPOSE AND SUMMARY OF TESTIMONY

**Q. What is the purpose of your testimony in this proceeding?**

A. I respond to the opening testimony of Julie Dyck, filed on behalf of the Commission Staff (Staff).

**Q. Please summarize your testimony.**

A. In my testimony, I address the following issues:

- I respond to Staff's questions and concerns about the fuel stock inventory balance for the Jim Bridger plant, the Hunter plant and the Naughton plant in the June 2023 base year compared with the December 2025 test year (Test Year);
- In response to adjustments and concerns from Staff, I provide explanation and corrections to the recommendations made by Staff, specifically related to an increase in the fuel stock at the Jim Bridger plant and its impact to the revenue requirement;
- Finally, I address Staff's questions about how the Company considers an increase in the forecasted value of fuel stock at Jim Bridger plant to be reasonable and prudent and why there are reasons and a need to maintain a certain level of coal inventory at the Jim Bridger plant.

## III. RESPONSE TO STAFF

**Q. Does your testimony provide an update to the coal fuel stock balances?**

A. Yes, my testimony focuses primarily on updates and corrections to the fuel stock balances for the Jim Bridger plant, the Hunter plant and the Naughton plant. The

changes highlighted in my testimony are due to an update to the analysis done to compare the fuel stock balances of each plant submitted in the initial filing with the current balance of year projections and forecasts for 2024 through 2025.

In the initial filing, filed in February 2024, the Company submitted the fuel stock inventory balances for the Test Year based on the 2024 budget, which was completed in August 2023. In 2023, the coal market was still experiencing unprecedented price increases and significant market fluctuations, which caused shortages in the coal market and resulted in fewer delivered tons than specified in the terms of several of PacifiCorp's coal supply agreements (CSA). In order to update the fuel stock balance and forecast for the Test Year, PacifiCorp conducted a detailed analysis of the fuel stock inventory, current projections for calendar year 2024, and target inventory levels. The updates are provided in Confidential Table 1 below, which shows the coal fuel stock balance in tons for each plant in the reply update compared to the initial filing.

**Confidential Table 1**

| Fuel Stock Inventory (Tons) | | | | |
|---|---|---|---|---|
| **Plant** | **Initial Filing (December 2025)** | **Reply Update (December 2025)** | **Initial Filing (13-Month Average)** | **Reply Update (13-Month Average)** |
| COLSTRIP | [redacted] | | | |
| CRAIG | | | | |
| DAVE JOHNSTON | | | | |
| HAYDEN | | | | |
| HUNTER | | | | |
| HUNTINGTON | | | | |
| JIM BRIDGER | | | | |
| NAUGHTON | | | | |
| WYODAK | | | | |
| **TOTAL** | | | | |

*The fuel stock balances shown for Colstrip, Craig, Hayden, Hunter and Jim Bridger are PacifiCorp's share.

Confidential Table 2 provides an update to the fuel stock balance in dollars. The 13-month average (December 2024 through December 2025) is used for calculating PacifiCorp's fuel stock balances for the 2025 Test Year.

**Confidential Table 2**

| Fuel Stock Inventory (Dollars) | | | | |
|---|---|---|---|---|
| **Plant** | **Initial Filing (December 2025)** | **Reply Update (December 2025)** | **Initial Filing (13-Month Average)** | **Reply Update (13-Month Average)** |
| COLSTRIP | [redacted] | | | |
| CRAIG | | | | |
| DAVE JOHNSTON | | | | |
| HAYDEN | | | | |
| HUNTER | | | | |
| HUNTINGTON | | | | |
| JIM BRIDGER | | | | |
| NAUGHTON | | | | |
| WYODAK | | | | |
| **TOTAL** | | | | |

*The fuel stock balances shown for Colstrip, Craig, Hayden, Hunter and Jim Bridger are PacifiCorp's share.

**Q. Why did the coal fuel stock balance at the Hunter plant increase?**

A. The Hunter plant's 13-month average, used for calculating PacifiCorp's fuel stock balance for year 2025, changed from [redacted] in the initial filing to [redacted] in the reply update and from [redacted] tons in the initial filing to [redacted] tons in the reply update. These changes are primarily a result of PacifiCorp executing an amendment to its CSA with Wolverine Fuels Sales, LLC (Wolverine), the Hunter/Wolverine CSA second amendment, on February 15, 2024, just shortly after the submission of the initial filing in this proceeding which provides for additional coal supply in 2025. The additional coal provided by the amended Hunter/Wolverine CSA will increase the coal supply to the Hunter plant during 2025 and is a key factor in increasing the fuel stock balance to a level that is nearer to the recommended amount per PacifiCorp coal inventory policies and studies performed by third-party

consultants. The Hunter plant fuel stockpile which has a capacity of 2,000,000 tons was near all-time lows in 2023 with PacifiCorp's allocated share of the stockpile ranging between [redacted] tons and [redacted] tons due to coal shortages and other factors beyond PacifiCorp's control as described more fully in my reply testimony in the 2025 Transition Adjustment Mechanism (TAM), docket UE 434.

At the time of the initial filing of this proceeding, PacifiCorp based its fuel stock balance on the 2024 budget, which did not include the updated price and coal volumes from the Hunter/Wolverine CSA second amendment in its analysis. The fuel stockpile amounts in this reply update include the amended Hunter/Wolverine CSA coal delivery amounts.

**Q. Did PacifiCorp make any changes to the fuel stock balance at the Naughton plant?**

A. Yes, PacifiCorp discovered an error in the Naughton plant fuel stock balance after the initial filing. The Company is therefore correcting the Naughton plant's fuel stock inventory balance (13-month average) of [redacted] tons in the initial filing to [redacted] tons in the reply update. The fuel stock inventory 13-month average dollar amount changed from $[redacted] in the initial filing to [redacted] in the reply update. These corrections update the Company's total value of fuel stock inventory balance, as reflected in Confidential Table 1 and Confidential Table 2 above.

**Q. Staff expresses concern that the coal fuel stock tonnage at the Jim Bridger plant increased from [redacted] tons as of December 2023 to [redacted] tons forecasted as of December 2025, even after the conversion of Jim Bridger Units 1 and 2 to natural gas.[1] Please respond.**

A. The coal fuel stock inventory provided in the initial filing for the Jim Bridger plant, was based on the 2024 budget, prepared in 2023. However, the reply update now includes the most recent updated values for the Jim Bridger fuel stock inventory balance in tons and dollars. The 13-month average coal fuel stock inventory at Jim Bridger decreased from [redacted] tons in the initial filing to [redacted] tons in the reply update and the fuel stock inventory 13-month average in dollars decreased from [redacted] in the initial filing to [redacted] in the reply update, as reflected in Confidential Table 1 and Confidential Table 2 above.

The decrease in the fuel stock inventory balance at the Jim Bridger plant is due to several factors, but primarily the changing fuel suppliers mix for the Jim Bridger plant. The Jim Bridger plant has been historically supplied by the Bridger Coal Company (BCC) underground and surface mines, as well as the Black Butte mine and recently a Powder River Basin (PRB) mine. The underground mine at BCC ceased operations in 2021, [redacted], leaving only two remaining suppliers of coal to the plant. The Jim Bridger plant now has a higher risk of coal supply disruption in 2025 and going forward with fewer coal supply options available. The only local source of coal supply for the Jim Bridger plant is now the BCC surface mine. The other available coal source is the PRB which

[1] Staff/800, Dyck/11.

is located approximately 550 miles away from the plant and the volume of PRB coal that can be delivered by rail is limited. Because the Jim Bridger plant is supplied by BCC, which is owned and operated by PacifiCorp, the Company intends to utilize Company-owned coal resources before purchasing coal from a third-party supplier to meet inventory targets and minimize costs. At the time of the initial filing, the coal fuel stock tonnage for Jim Bridger plant was forecast to increase between December 2023 and December 2025 based on assumptions of deliveries and consumption that resulted in building inventory to [redacted]. This inventory would be used as needed to meet the Jim Bridger plant load requirements until it is depleted or until the plant ceases operations. Confidential Table 3 below provides a breakdown of the Jim Bridger plant inventory targets as established in the PacifiCorp Coal Inventory Policies and Procedures which was provided on April 8, 2024, as a response to discovery from Commission Staff (OPUC Data Request 199). The coal inventory policies and procedures document is also provided as Confidential Exhibit PAC/3001.

**Confidential Table 3**

| Jim Bridger Plant - Inventory Targets | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Target Levels through December 31, 2023 | | | | | | | | |
| | | | | | Target Levels | | | |
| | | | | | Days Burn | | Tons | |
| Stockpile | Net Capacity megawatts (MW) | Annual Burn (Tons) | Daily Burn (Tons) | Plant/Mine Capacity (Tons) | Low | High | Low | High |
| Jim Bridger - PAC | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Jim Bridger - Total | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Target Levels after Jim Bridger Units 1 & 2 convert to natural gas, effective January 1, 2024. | | | | | | | | |
| | | | | | Target Levels | | | |
| | | | | | Days Burn | | Tons | |
| Stockpile | Net Capacity megawatts (MW) | Annual Burn (Tons) | Daily Burn (Tons) | Plant/Mine Capacity (Tons) | Low | High | Low | High |
| Jim Bridger - PAC | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Jim Bridger - Total | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

*Annual burn reflects the amount that the Jim Bridger plant can consume in a year while the plant ending inventory reflects coal fuel stock available at a given point in time.

**Q. Staff recommends that if the majority of Jim Bridger plant's permitted inventory capacity is inactive storage, the Company should not earn a return at the expense of rate payers.[2] Please clarify.**

A. The long-term storage at the Jim Bridger Plant is not inactive coal or an impaired Company asset ineligible to earn a return from ratepayers. The Jim Bridger plant coal inventory consists of two main stockpiles located adjacent to the plant. The total, PacifiCorp plus Idaho Power, maximum permitted average stockpile capacity is [redacted] tons which consists of [redacted] tons of short-term (active) storage and [redacted] tons of long-term (dead) storage. As per the permit requirement, issued by the state of Wyoming Department of Environmental Quality, the Jim Bridger plant is allowed to maintain a 12-month calendar-year average of no more than [redacted] tons of short-term and [redacted] tons of long-term coal inventory. Coal may be transferred without limit from the long-term pile to the short-term pile; however, the

[2] Staff/800, Dyck/12.

permit places a limit of [redacted] tons per year of transfers from the short-term pile back to the long-term pile.

It is common industry practice to use the permitted quantity of coal from a long-term (dead) storage stockpile, in order to serve as a safety pile to meet the generation requirement and to maintain a reliable supply of fuel at the plant. PacifiCorp generally uses both short-term storage and long-term storage to meet the generation requirement of the plant. In fact, between August 2022 and September 2023, [redacted] tons of the long-term storage pile was transferred to the active pile in order to provide a reliable coal supply for the Jim Bridger plant. As evidenced by this very recent action, the long-term storage pile is not inactive as Staff asserts.

PacifiCorp maintains system and plant inventory ranges which are reviewed and evaluated periodically by the Company in order to determine if the ranges are adequate to provide an economic and reliable supply of fuel to the generating stations. These evaluations consider factors, including but not limited to: transportation, coal quality, market conditions, potential disruptions, laws and regulations, and uncertainties in weather. While the price of coal fuel is not a primary factor in determining plant inventory levels, PacifiCorp's internal coal inventory policies and procedures do not preclude the Company from prudently purchasing coal from third-party coal suppliers when coal prices are low.

Furthermore, maintaining inventory at coal generating stations is a prudent industry practice and is not practiced solely for financial reasons. Coal stockpiles support continuity of operations and efficiency in the event of supply or transportation disruptions, labor disruptions, changes to environmental laws and

regulations, and uncertainties in weather. The Company has established targeted stockpile ranges according to its inventory policies but is also required to establish and maintain those target levels by other state regulatory commissions and agencies as market conditions permit. PacifiCorp is also required by Wyoming and Utah state environmental agencies to maintain coal stockpiles within certain ranges.

**Q. Staff asserts that the Company has not provided any financial analysis demonstrating it considered market conditions, environmental impact, risk, or the trade-offs between the costs of inventory versus the costs associated with coal shortages and lost electricity sales or generation replacement costs or for storing fuel stock at near capacity levels at Jim Bridger plant. Staff also asserts that the forecasted value of fuel stock at Jim Bridger plant is not reasonable or prudent.[3] Please respond.**

A. PacifiCorp has employed third-party consulting groups who have conducted financial analysis and studies using complex models to establish and evaluate existing coal inventory policy and provide recommendations for achieving coal inventory targets and limits at coal generating stations, including the Jim Bridger plant. The most recent third-party study was performed in 2021 and was provided on June 14, 2024, as a response to discovery from Commission Staff (OPUC Data Request 641). The study is also provided as Confidential Exhibit PAC/3002.

The 2021 inventory study states, [redacted]

[3] Staff/800, Dyck/11-12.

[redacted][4]

The Executive Summary of this 2021 inventory study also states, [redacted]

[redacted][5]

**Q. Has the fueling plan and the fueling options for the Jim Bridger plant been regularly reviewed by the Commission?**

A. Yes. The Commission has regularly reviewed these fueling plans in PacifiCorp's past TAM proceedings. The plant inventory levels at Jim Bridger are maintained to support the short-term and long-term fueling needs of Jim Bridger plant. The fueling plans evaluate how PacifiCorp can best meet the fueling needs, including inventory targets, of the Jim Bridger plant throughout the operational life of the plant, given the assumptions from the integrated resource plan, and other changing circumstances affecting the plant over the next several years. The Commission has thoroughly

[4] PAC/3002, p. 4.
[5] PAC/3002, p. 2.

reviewed the reasonableness of the Company's strategy, including the reasonableness of storing and maintaining certain levels of coal inventory at the Jim Bridger plant.

**Q. Staff recommends an adjustment to fuel stock of $25.9 million at the system level, or $6.8 million Oregon allocated, to account for the imprudent holding of additional coal at the Jim Bridger plant.[6] Is this a reasonable recommendation?**

A. No, as explained in detail above, the coal fuel stock inventory at the short-term (active) storage and the long-term (dead) storage at the Jim Bridger plant is compliant with the inventory levels set by the Wyoming state environmental agencies and the regulatory target mandates set by other state regulatory commissions. The Company has also provided a detailed explanation of how the change in fuel stock balance impacts the Company's revenue requirement. Please refer to the reply testimony of Company witness Sherona L. Cheung for a more detailed discussion of how the change in fuel stock balance in the reply update impacts the revenue requirement. Additionally, PacifiCorp has taken reasonable steps to maintain reliable inventory levels to meet generation needs at the Jim Bridger plant. Therefore, PacifiCorp's coal fuel stock inventory amount at the Jim Bridger plant, as updated in the reply testimony is reasonable, prudent and at an amount that is in the best interest of its customers.

**Q. Does this conclude your reply testimony?**

A. Yes.

[6] Staff/800, Dyck/16.

**REDACTED**
Docket No. UE 433
Exhibit PAC/3001
Witness: James C. Owen

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**REDACTED**

**Exhibit Accompanying Reply Testimony of James C. Owen**

**PacifiCorp Coal Inventory Policies and Procedures**

**July 2024**

# THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

**REDACTED**
Docket No. UE 433
Exhibit PAC/3002
Witness: James C. Owen

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**REDACTED**

**Exhibit Accompanying Reply Testimony of James C. Owen**

# Coal Inventory Study for PacifiCorp Coal-Fired Power Plants in Wyoming and Utah

**July 2024**

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**REDACTED**
Docket No. UE 433
Exhibit PAC/3100
Witness: Ramon J. Mitchell

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**REDACTED**

# Reply Testimony of Ramon J. Mitchell

**July 2024**

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## I. INTRODUCTION

**Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).**

A. My name is Ramon J. Mitchell, and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Director, Net Power Costs.

**Q. Please describe your education and professional experience.**

A. I received a Master of Business Administration degree from the University of Portland and a Bachelor of Arts degree in Economics from Reed College. I was first employed by the Company in 2015 and during my time at the Company I have held various positions in the regulation, merchant, and transmission departments. After a brief departure from the Company in 2021, in 2022 I returned and now serve as Director, Net Power Costs. In my current role I am responsible for leading and overseeing various efforts associated with the Company's net power costs (NPC).

**Q. Have you testified in previous regulatory proceedings?**

A. Yes. I have previously provided testimony to the Public Utility Commission of Oregon (Commission), as well as commissions in California, Idaho, Utah, Washington, and Wyoming.

## II. PURPOSE OF TESTIMONY

**Q. What is the purpose of your reply testimony in this proceeding?**

A. I respond to the opening testimony of Commission Staff witness Madison Bolton (Staff).

**Q. Please summarize your testimony.**

A. Through my testimony, I address the following issues:

- The Company's forecasts of Qualifying Facility (QF) generation produce reasonably accurate results when compared to other components of NPC and the Company does not support limiting Staff's proposed dollar-for-dollar pass-through to one line item of NPC.
- To the extent the Commission is inclined to adopt dollar-for-dollar pass-through for QF costs: (1) there is no reason to limit dollar-for-dollar pass-through to only QF costs. Staff's proposal is unreasonably narrow because it isolates a single component of NPC; and (2) Staff's proposed methodology has significant issues that preclude potential implementation and is not suitable for PacifiCorp's multi-jurisdictional system.

## III. QUALIFYING FACILITIES

**Q. What is a QF?**

A. A class of generating facilities, consisting of small power production facilities and cogeneration facilities, that receive special rate and regulatory treatment under the Public Utility Regulatory Policies Act of 1978 (PURPA).

A small power production facility is a generating facility of 80 megawatts (MW) or less whose primary energy source is renewable (hydro, wind or solar), biomass, waste, or geothermal resources. A cogeneration facility is a generating facility that sequentially produces electricity and another form of useful thermal energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy.

These facilities enjoy: (1) the right to sell energy or capacity to a utility; (2) the right to purchase certain services from utilities; and (3) relief from certain

regulatory burdens.

With limited exceptions, QFs generally have the option of selling to a utility either at the utility's avoided cost or at a negotiated rate. Avoided cost is the incremental cost to an electric utility of electric energy or capacity which, but for the purchase from the QF, such utility would generate itself or purchase from another source.[1]

**Q. What relevant, prior discussions have taken place regarding QFs in previous filings?**

A. In the prior general rate case (GRC),[2] Staff recommended "that QF costs be recovered as a pass-through of NVPC [*sic*] in the PCAM proceeding."[3] Staff's reasoning for their recommendation rested on three assertions: (1) "Oregon-regulated electric utilities are required to buy power from QFs at rates established by the Commission;" (2) "the current process […] incentivize[s] the Company to over forecast its QF costs;" and (3) "Staff's proposed approach will ultimately benefit consumers by reducing the workload of intervening parties in each docket."[4]

## A. Clarifications to Staff's Testimony

**Q. Before discussing Staff's current QF recommendation(s) in this GRC, do you have any clarifications to make regarding Staff's testimony?[5]**

A. Yes, there are four clarifications.

[1] *PURPA Qualifying Facilities*, FEDERAL ENERGY REGULATORY COMMISSION, https://www.ferc.gov/qf (accessed Jul. 19, 2024).
[2] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*. Docket No. UE 399, Staff/900, Enright/25-31.
[3] Docket No. UE 399, Staff/900, Enright/27.
[4] Docket No. UE 399, Staff/900, Enright/29.
[5] Staff/2100.

**Q. What is your first clarification?**

A. Staff asserts that the Company supported the recommendation made by Staff in the Company's prior GRC. Staff's recommendation from the prior GRC was that "QF costs be recovered as a pass-through of NVPC [*sic*] in the PCAM proceeding."

For the record, the Company supported Staff's proposal from the viewpoint that "it is just and reasonable for customers to pay the prudent power costs incurred to serve load, and that **all costs** [emphasis added] included in the TAM should true-up to actuals without application of the deadbands, sharing bands, and earnings test."[6]

Additionally, the Company did not agree with Staff's proposed methodology and noted that "the methodology would need to be modified to fit PacifiCorp's wider geographical footprint."[7]

**Q. What is your second clarification?**

A. Staff asserts that "QF costs [are] forecasted to be over $316 million and 12.5 percent of NVPC in the 2025 TAM." Staff therefore concludes that "the potential impact to customers or the Company is not de minimis."[8] Notwithstanding the lack of specificity on what does or does not constitute an impact being de minimis, this assertion is made within Staff's overarching narrative that "QFs are a must-take resource, and an avoided cost calculation determines their price." Staff views the price as problematic because "[a]voided cost calculations are based on forecasts, which inevitably introduce some amount of lag between avoided costs and the actual prices that a competitive solicitation or market produces."[9] Staff also notes that

[6] Docket No. UE 399, PAC/1500, Wilding/16.
[7] Docket No. UE 399, PAC/1500, Wilding/16.
[8] Staff/2100, Bolton/4.
[9] Staff/2100, Bolton/3.

"[a]dditionally, PacifiCorp must meet small-scale renewable resource requirements for resources 20 MW or smaller as part of HB 2021, which will likely increase the percentage of QF costs in NVPC."[10]

**Q. Is Staff's understanding of QF pricing in the Company's NPC correct?**

A. No. Since 2020 the Company has remedied Staff's concern on avoided cost pricing as it concerns QFs that are not within Oregon's jurisdiction. The 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol), section 4.4,[11] established that "the energy output of New [QFs] will be […] priced at a forecasted reasonable energy price […] and any cost of a New [QF] above the forecasted reasonable energy price will be situs assigned and allocated to the State of Origin.[12] The forecasted reasonable energy price is a single blended market price derived from the Company's Official Forward Price Curve ("OFPC"), scaled for hourly prices, that was used for setting QF pricing for the New [QF]."[13]

**Q. What does this mean for QF pricing in the Company's Oregon rates?**

A. The magnitude of QF volumes and costs that will not be representative of actual prices that a competitive solicitation or market produces,[14] will not be as large as Staff's testimony suggests when considering that all QF contracts executed, renewed, amended or extended (i.e., New QFs)[15] in other (non-Oregon) states after January 1, 2020 are valued to Oregon customers at then prevailing market prices—situs assigned

[10] Staff/2100, Bolton/5-6.
[11] *PacifiCorp Initiates Investigation into Multi-Jurisdictional Issues*, Docket No. UM 1050, PAC/101, Lockey/32 (Dec. 6, 2019).
[12] The state having jurisdiction over the QF for avoided cost pricing.
[13] *PacifiCorp Initiates Investigation into Multi-Jurisdictional Issues*, Docket No. UM 1050, PAC/101, Lockey/35 (Dec. 6, 2019).
[14] *See* Staff/2100, Bolton/3-4.
[15] Unless there is no change to the contract pricing.

to the State of Origin—and only QFs under Oregon's jurisdiction, or QFs with unchanged contracts from prior to January 1, 2020 may have prices that are not representative of what a competitive solicitation or market produces. Furthermore, on execution of the next iteration of cost allocation, the expectation is that all QFs will be situs assigned and allocated to the State of Origin, leaving the relevant QFs as only those under Oregon's jurisdiction.

**Q. What are the details of those relevant QFs under Oregon's jurisdiction?**

A. For Oregon jurisdictional QFs, costs are forecasted to be approximately $92 million *total-Company*, which represent 3.6 percent of NPC in the 2025 Transition Adjustment Mechanism (TAM).

**Q. What is your third clarification?**

A. Staff asserts that one of the benefits of passing QF costs through the power cost adjustment mechanism (PCAM) is that it "removes the [Company's] incentive to over-forecast QF costs."[16] More specifically, Staff asserts that "[w]hen QF costs are higher than market purchases or a utility's self-generation, the Company has an incentive to over-forecast,"[17] and "[a] pass-through removes the incentive for the Company to use over-forecasting of QFs as a buffer to wholesale price exposure."[18] Taking Staff's logic to the next step, it is therefore implied that when QF costs are *lower* than market purchases or a utility's self-generation, the Company has an incentive to *under-forecast*. Taking this logic to its conclusion, the Company has an incentive to under-forecast all generation sources with costs lower than market

[16] Staff/2100, Bolton/5.
[17] Staff/2100, Bolton/3.
[18] Staff/2100, Bolton/6.

purchases or self-generation, and an incentive to over-forecast all generation sources with costs higher than market purchases or self-generation.

**Q. What does the data show?**

A. Since the Company's NPC in the TAM use a forecast of wind generation and hydroelectric generation as an input to the production cost model—**regardless of whether those generation sources are QFs, conventional purchased power agreements, or Company owned—**Staff's logic indicates that one would observe an under-forecast of Company-owned wind and hydroelectric generation, which have no (zero dollars per megawatt-hour ($/MWh)) marginal fuel costs. However, the data show no such thing. The data show the exact opposite, the Company has been persistently over-forecasting wind generation and hydroelectric generation as illustrated in Confidential Table 1 'NPC and Components Over / Under Forecast'.

Furthermore, during the 2023 TAM, the 2024 TAM and the 2025 TAM, QF costs have been *lower* than the price of market purchases on average. Therefore, Staff's logic would suggest that the Company had an incentive to *under-forecast* QF costs in those proceedings, yet the data show no such thing, as illustrated in Confidential Table 1. More generally, the fundamental logic espoused by Staff implies that the Company should be persistently *over-forecasting* NPC. Again, the data show the exact opposite.

The data show that Staff's incentive based arguments in this testimony are not valid for the Company's NPC.

**Confidential Table 1**
**NPC and Components Over / Under Forecast**

**Q. What is your fourth clarification?**

A. Staff describes the comparison of QF output actuals vs. forecasts as a "routinely contentious issue among stakeholders."[20] However, with the exception of Staff, the last occasion of contention appears to have been in the 2018 TAM, wherein the Oregon Citizens' Utility Board advocated for a change to the forecasting methodology for QFs by incorporating a contract delay rate, which was adopted—in a modified form—by the Commission.[21] In the last seven TAMs, from the 2019 TAM to the 2025 TAM, it appears that the only party that has taken issue with QF forecasts is Staff.

[19] Percentages are based on MWh variance with the exception of NPC which is based on dollar variance.
[20] Staff/2100, Bolton/6.
[21] *In the Matter of PacifiCorp d/b/a Pacific Power, 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Order No. 17-448 at 17, fn. 2 (Nov. 6, 2017).

**B. Staff's Recommendation**

**Q. Please explain Staff's recommendation(s) regarding QFs in this GRC.**

A. Staff recommends that the Company "alter its current forecasting and cost-recovery methodology for QF costs by switching to a dollar-for-dollar pass through mechanism."[22] Staff's recommendation to pass through this single line item in NPC is premised on the following four positions.

**First**, Staff asserts that "[w]hen QF costs are higher than market purchases or a utility's self-generation, the Company has an incentive to over-forecast to reduce exposure to higher QF costs. This is problematic as it creates risk for customers **in the form of higher total Net Variable Power Costs (NVPC)** [*sic*] [emphasis added]."[23]

**Second,** Staff asserts that "[w]hen QF costs are lower than market prices, over-forecasting leaves the Company and customers exposed to the higher market costs."[24]

**Third,** Staff asserts that "with QF costs forecasted to be over $316 million and 12.5 percent of NVPC in the 2025 TAM, the potential impact to customers or the Company is not de minimis,"[25]

**Fourth,** Staff justifies focusing only on this single line item in NPC based on the assertion that "[a] one-for-one recovery of QF costs is also reasonable because QFs are federally mandated resources that the Company must take. Since the Company does not have control over QF procurement and their optimization, neither

[22] Staff/2100, Bolton/2.
[23] Staff/2100, Bolton/3.
[24] Staff/2100, Bolton/3-4.
[25] Staff/2100, Bolton/4.

the Company nor the customer need to be solely responsible for the risks associated with cost recovery."[26]

**Q. What is your reply to Staff's first position?**

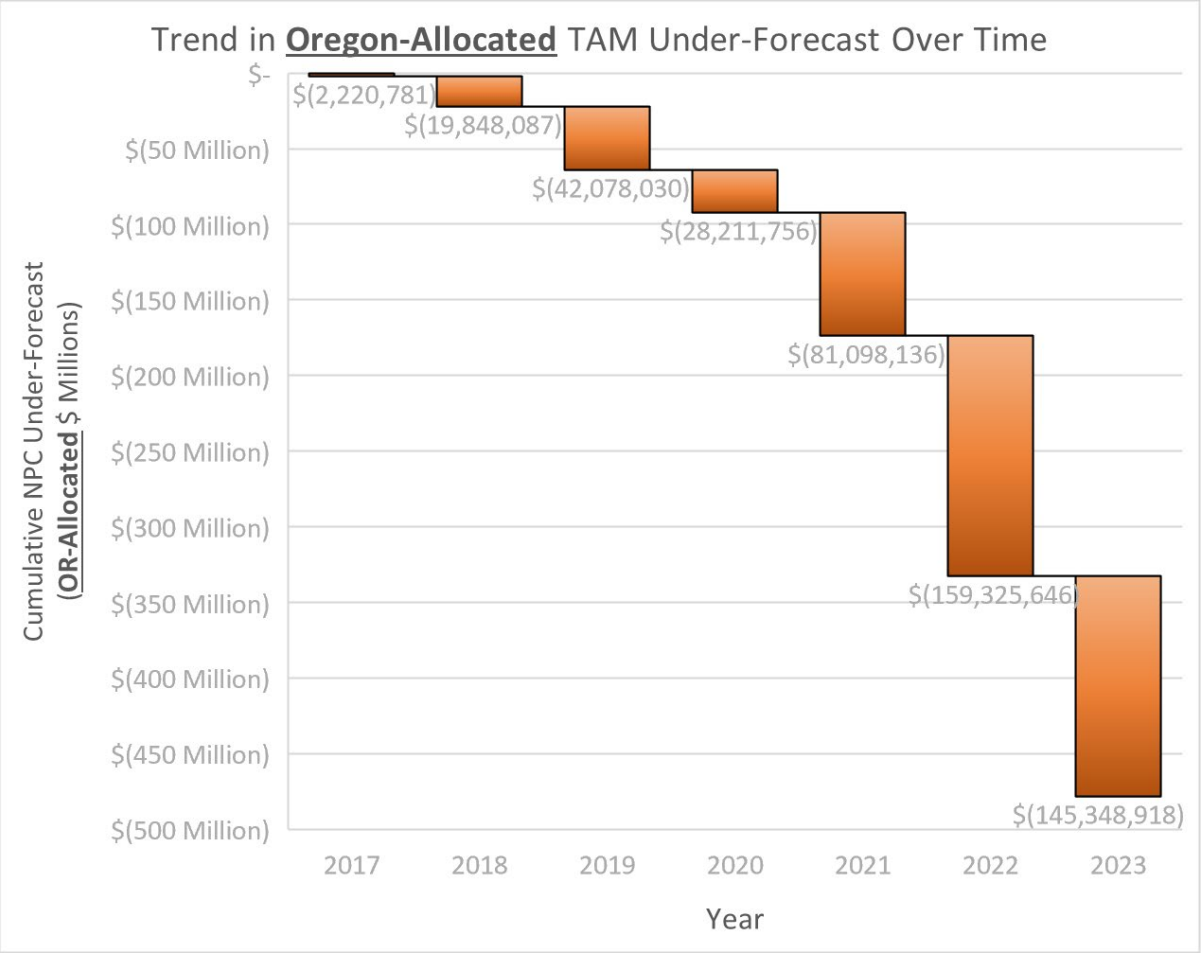
A. Staff asserts that "[w]hen QF costs are higher than market purchases or a utility's self-generation, the Company has an incentive to over-forecast to reduce exposure to higher QF costs. This is problematic as it creates risk for customers **in the form of higher total Net Variable Power Costs (NVPC)** [*sic*] [emphasis added]."[27]

I have already rebutted, with data, that Staff's logic on incentives does not hold true for the Company's NPC since $0/MWh wind generation and $0/MWh hydroelectric generation are also being over-forecasted by substantial amounts, and this unilaterally *reduces* the Company's forecast NPC since these resources are lower cost than market purchases or self-generation with marginal fuel costs.

Notwithstanding the above, Staff's reference to the risk of "higher total Net Variable Power Costs (NVPC) [*sic*]"[28] is perplexing given that the data unequivocally show that the Company has been persistently putting lower than actual NPC into customer rates, which flows through the PCAM as a benefit to customers as compared to a pass through. This is illustrated in Figure 1 'Realized Risk of NPC Under-Forecasts.'

[26] Staff/2100, Bolton/5.
[27] Staff/2100, Bolton/3.
[28] Staff/2100, Bolton/3.

**Figure 1**
**Realized Risk of NPC Under-Forecasts**




**Q. What is your reply to Staff's second position?**

A. Staff asserts that "[w]hen QF costs are lower than market prices, over-forecasting leaves the Company and customers exposed to the higher market costs."[29] As an initial matter, this scenario typically leaves only the Company exposed to higher market prices, as compared to the alternative of under-forecasting QFs. The structure of the current PCAM ensures this.

[29] Staff/2100, Bolton/3-4.

Regardless, hearkening back to Staff's incentive-based language; when QF costs are lower than market prices the Company would have an incentive to *under-forecast* QF costs, per Staff's logic. However, the data demonstrate that this logic does not hold for the Company's NPC. During the preparation of the 2023 TAM, all economic indicators, inclusive of the official forward price curve (OFPC), consistently showed that QF costs would be substantially lower than market prices on average. Furthermore, the Company simultaneously developed a new QF forecasting methodology within that 2023 TAM.

Taken altogether, were the Company incentivized as Staff implies, then one would expect the newly created QF forecasting methodology to produce an *under-forecast* of QF costs in the 2023 TAM. However, as illustrated in Confidential Table 1 above, the QF costs were over-forecasted, and the level of over-forecast maintained the same low magnitude as observed in the prior six years.

**Q. What is your reply to Staff's third position?**

A. Staff asserts that "with QF costs forecasted to be over $316 million and 12.5 percent of NVPC [*sic*] in the 2025 TAM, the potential impact to customers or the Company is not de minimis,"[30] As discussed above, the 2020 Protocol establishes a reasonable energy price for non-Oregon jurisdictional QFs that relies on then-prevailing market prices to value the QF rather than the QF contract prices. In this manner, Staff's calculation of the magnitude of QF costs which are at issue shows costs that are too high. Focusing on Oregon jurisdictional QFs, costs are forecasted to be approximately $92 million, which represent 3.6 percent of NPC in the 2025 TAM.

[30] Staff/2100, Bolton/4.

**Q. What is your reply to Staff's fourth position?**

A. Staff justifies focusing only on this single line item in NPC based on the assertion that "[a] one-for-one recovery of QF costs is also reasonable because QFs are federally mandated resources that the Company must take. Since the Company does not have control over QF procurement and their optimization, neither the Company nor the customer need to be solely responsible for the risks associated with cost recovery."[31] However, this portrays an extraordinarily incomplete picture of the Company's operations.

As a first example, power prices and natural gas prices in the spot market are prices that the Company must take (price taker) as the Company is mandated to provide load service. The Company has no control over the level of these market prices. Therefore, Staff's logic suggests that neither the Company nor the customer need to be solely responsible for the risks associated with cost recovery for unexpected spot market price changes.

As a second example, unexpected weather events, whether unanticipated heat waves or cold snaps, are system conditions that the Company must take, since the Company has no control over the weather. Therefore, Staff's logic suggests that neither the Company nor the customer need to be solely responsible for the risks associated with cost recovery for unexpected changes in weather.

As a third example, transmission outages on non-Company transmission lines must be taken by the Company since the Company has no control over the operation or maintenance of these transmission lines. Therefore, Staff's logic suggests that

[31] Staff/2100, Bolton/5.

neither the Company nor the customer need to be solely responsible for the risks associated with cost recovery for unexpected transmission outages on non-Company transmission.

These kinds of examples are numerous, and by no means limited to the above three. However, Staff has made no proposal to ensure that neither the "Company nor the customer need to be solely responsible for the risks associated with cost recovery"[32] as it concerns these other facets of the system that the Company has no control over.

**Q. From these rebuttals of Staff's positions, what is the Company's position?**

A. Staff's positions that support their recommendation are not supported by the evidence. Therefore, Staff's recommendation should be rejected without a larger review of the deadbands, sharing bands, and earnings test.

Staff's fixation on QF forecasting is perplexing given that the QF forecast is relatively accurate,[33] particularly when compared to the persistent under-forecasting of overall NPC as illustrated in Figure 1. While the Company is working to constantly improve its forecasting models, Staff's emphasis on any over-forecast of QF costs is misplaced. The aggregate QF forecast error percentage is substantially lower in magnitude than the total-Company NPC forecast error, wind generation forecast error, hydroelectric generation forecast error, etc.

Regardless, the Company has long sought dollar-for-dollar recovery of all NPC through the PCAM and generally welcomes parties' support for pass-through

[32] Staff/2100, Bolton/5.
[33] Staff/2100, Bolton/3, Figure 1.

proposals, in principle.[34] However, Staff's proposal is unreasonably narrow because it isolates a single component of NPC—and one that is relatively accurate—for dollar-for-dollar recovery. Staff's proposal is also unreasonably one-sided because it focuses on a single cost that has been historically over-forecast, while ignoring that overall NPC (along with many other single NPC components) have been historically under-forecast.

**Q. Do you have any other comments on Staff's recommendation?**

A. Yes. First, "Staff is recommending that PacifiCorp alter its current forecasting and cost-recovery methodology."[35] Regarding the altering of the Company's current forecasting methodology, Staff recommends a methodology of forecasting such that "[i]n the TAM, the Company would forecast QF costs using a multi-year moving average of historical QF generation while also including new QFs with commercial operation dates (CODs) in the test year."

However, this is already the methodology that the Company uses to forecasts QFs, as stipulated and ordered in the 2023 TAM.[36] Furthermore, it was Staff who advocated for this change in methodology. It is unclear to the Company as to why Staff describes the continuation of the Company's current QF forecast methodology as an alteration to current forecasting.

**Second**, Staff displays QF forecast error percentages starting in 2015,[37] and notes that an over-forecast "trend has persisted since 2016."[38] However, the

[34] *See e.g., In the Matter of PacifiCorp, dba Pacific Power, Transition Adjustment Mechanism*, Docket No. UE 399, PAC/2600, Wilding/11 (Sept. 4, 2022).
[35] Staff/2100, Bolton/2.
[36] Order No 22-389, Appendix A at 16.
[37] Staff/2100, Bolton/3, Figure 1.
[38] Staff/2100, Bolton/2.

Commission ordered the Company to implement a contract delay rate adjustment beginning in the 2018 TAM for forecasts of calendar year 2018 forward.[39] Years prior to 2018 are not comparable to 2018 or years after, and it is inappropriate to display forecast error percentages for those years prior to 2018. However, Staff has inappropriately used that QF data prior to 2018, to assess QF forecasts after 2018, in the 2020 TAM,[40] the 2021 TAM,[41] the 2022 TAM,[42] the 2023 TAM,[43] the 2024 TAM,[44] and the current 2025 TAM.[45]

## C. Staff's Proposed Formulaic Methodology

**Q. Notwithstanding your rejection of Staff's recommendation, do you have any comments on the methodology under which Staff proposes its recommendation should function?**

A. Yes. Disregarding the portion of Staff's proposed methodology which has the Company continuing with its current forecast methodology, as discussed above, Staff proposes that: (1) "[i]n the PCAM, PAC's actual QF costs would be compared to the forecasted costs, including the forecasted Mid-C prices, and the resulting surplus or deficit would be passed through as either a charge or a refund to customers based on the day-ahead forecasted Mid-C power price for replacement power, or the difference

[39] Order 17-448 at 17fn. 2.
[40] *In the Matter of PacifiCorp, dba Pacific Power, 2020 Transition Adjustment Mechanism*. Docket No. UE 356, PAC/400, Wilding/31.
[41] *In the Matter of PacifiCorp, dba Pacific Power, 2021 Transition Adjustment Mechanism*. Docket No. UE 375, PAC/500, Webb/70.
[42] *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*. Docket No. UE 390, PAC/400, Staples/74-75.
[43] *In the Matter of PacifiCorp, dba Pacific Power, 2023 Transition Adjustment Mechanism*. Docket No. UE 400, PAC/600, Mitchell/59.
[44] *In the Matter of PacifiCorp, dba Pacific Power, 2024 Transition Adjustment Mechanism*. Docket No. UE 420, Staff/500, Bolton/4.
[45] *In the Matter of PacifiCorp, dba Pacific Power, 2024 Transition Adjustment Mechanism*. Docket No. UE 434, Staff/500, Bolton/6-7.

between the forecasted Mid-C price and the QF contract price in the event of surplus generation;"[46] and (2) "[t]he price for the forecasted Mid-C price would include a weighting of the light load and heavy load hours by the respective hours in the day."[47] There are five issues with this proposal.

**Q. What is the first issue related to Staff's proposed methodology?**

A. If QF volumes are over-forecasted, the variance in QF volumes between the forecast and the actuals is valued at the difference between a Mid-Columbia (Mid-C) power trading hub price and the QF contract price. This attempts to value the volume variance at the price the Company paid for a certain amount of QF volume as compared to the price the Company could receive for selling that certain amount of QF volume.

However, if QF volumes are under-forecasted, Staff proposes that the variance in QF volumes be valued at a Mid-C price, without any consideration of the QF price. For consistency or accuracy, in the event of QF volume under-forecast, the valuation should be at the price the Company *would have* paid for a certain amount of QF volume as compared to the price the Company could incur for buying that certain amount of QF volume.

**Q. What is the second issue related to Staff's proposed methodology?**

A. Staff proposes to value QF volume variance at a monthly average Mid-C price which appears to be calculated by weighting all hours in the day (all 24 hours). However solar resources do not produce energy at night, and the Company has several Oregon

[46] Staff/2100, Bolton/4.
[47] Staff/2100, Bolton/4.

solar QFs. More appropriately, as the Company has previously suggested, the price used to value the QFs should be hourly scaled, consistent with the hourly scaling methodology applied to the OFPC in the TAM.[48]

**Q. What is the third issue related to Staff's proposed methodology**

A. Staff proposes to use only the Mid-C power trading hub to value QF volume variance. This approach may be appropriate for other utilities local to the region. However, it is not appropriate for the Company which has access to multiple power trading hubs across the western interconnection,[49] and the transmission capability to move energy across its service territory as economics dictate.

**Q. What is the fourth issue related to Staff's proposed methodology**

A. Staff's proposal advises "including new QFs with commercial operation dates (CODs) in the test year,"[50] but ignores, and thereby implies discontinuing, the Commission ordered requirement to use the contract delay rate methodology.

**Q. What is the fifth issue related to Staff's proposed methodology**

A. While Staff's proposed methodology uses forecast QF volume and actual QF volumes, it does not use forecast market prices and actual market prices. Instead, it only uses forecast market prices.[51] As discussed above, Staff has ignored a number of other facets of system conditions that the Company "must take," for example spot market power prices.

[48] Docket No. UE 399, PAC/1500, Wilding/16.
[49] For example, Four Corners, California Oregon Border, Mona, Nevada Oregon Border, Mead, Mid-C, and Palo-Verde.
[50] Staff/2100, Bolton/4.
[51] Staff/2100, Bolton/6.

If a pass through is justified when "[t]he Company does not have control," and if this enables "neither the Company nor the customer […] to be solely responsible for the risks associated with cost recovery,"[52] the following should hold true: Since the Company does not have control over spot market power prices, neither the Company nor the customer need to be solely responsible for those spot market power price risks associated with cost recovery. Therefore, Staff's proposed methodology, which uses forecast QF volume and *actual* QF volumes, should also use forecast market prices and *actual* market prices; not just forecast market prices.

## IV. ACCOUNTING UPDATE

**Q. Please describe the movement of costs from FERC account 555 to FERC account 509.**

A. On June 29, 2023, the FERC issued Order No. 898 (Docket No. RM21-11-000),[53] Accounting and Reporting Treatment of Certain Renewable Energy Assets, to change the accounting required for certain types of costs that have been previously booked to FERC Account 555 to be booked to FERC account 509. This change becomes effective on January 1, 2025.

**Q. What costs will be affected by FERC's Order No. 898 beginning January 1, 2025?**

A. The change in accounting affects the costs associated with greenhouse gas ("GHG") allowances that have been historically booked to FERC account 555. Specifically for NPC, these costs will be booked to FERC account 509, beginning January 1, 2025.

[52] Staff/2100, Bolton/5.
[53] *File Rule*, 183 FERC ¶ 61,205, Docket No. RM21-11-000 (Jun. 29, 2023) *available at* https://www.ferc.gov/media/order-no-898.

Correspondingly, for those costs which would have been booked to FERC account 555, the Company advises that they will now be booked to FERC account 509 and included in the requested recovery in the TAM and PCAM.

## V. CONCLUSION

**Q. What is your recommendation to the Commission?**

A. Staff's positions that support their recommendation are not supported by the evidence. Therefore, Staff's recommendation should be rejected without a larger review of the deadbands, sharing bands, and earnings test. I recommend that the Commission *not* adopt Staff's proposal for all the reasons outlined in this testimony.

**Q. Does this conclude your reply testimony?**

A. Yes.

Docket No. UE 433
Exhibit PAC/3200
Witness: Kenneth Lee Elder, Jr

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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# Reply Testimony of Kenneth Lee Elder, Jr

**July 2024**

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**Q. Are you the same Kenneth Lee Elder Jr who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?**

A. Yes.

## I. PURPOSE AND SUMMARY

**Q. What is the purpose of your testimony?**

A. My testimony responds to various issues raised about PacifiCorp's proposed load forecast filed June 28, 2024, raised in the opening testimony of Bret Stevens filed on behalf of the Public Utility Commission of Oregon (Commission) Staff (Staff).

**Q. Please summarize your testimony**

A. My testimony addresses four recommendations in Staff's testimony:

Staff recommends that in PacifiCorp's next Oregon rate case the Company:

1) Use algorithmically parameterized ARIMA models as the baseline model and document and explain any deviations from these prescribed models.
2) Present evidence either here or in its next general rate case showing that the use of the Statistically Adjusted End-Use (SAE) "XHeat" and "XCool" variables add a sufficient level of explanatory power above more transparent weather variables to justify their use.
3) Use a software which allows for differencing of models or present evidence for each of their models justifying the differencing, or lack thereof, for each model.
4) Host load forecasting workshops between now and the Company's next general rate case to facilitate Staff and Intervenor input into these analyses.

**Q. Please respond to Staff's[1] recommendation that in PacifiCorp's next Oregon rate case the Company should use algorithmically parameterized ARIMA models as the baseline model and document and explain any deviations from these prescribed models.**

A. The Company is concerned by Staff's suggestion that the Commission should mandate the modeling framework used by the Company in general rate cases. Such an order would create a disconnect between the forecast used in the Oregon general rate case, rate cases in other states, the Company's internal business planning, other proceedings such as the integrated resource plan (IRP) and create issues with allocation factors used to allocate costs between the states.

Furthermore, the Company has a long history of producing reliable forecasts that have been used in multiple proceedings to set just and reasonable rates. There are already true up mechanisms in many states such as the transition adjustment mechanism (TAM) and the power cost adjustment mechanism (PCAM) in Oregon to protect customers and the Company from unforeseen changes in actual load among other impacts.

Finally, while Staff is correct that there are free software solutions available to implement his proposed changes, this ignores the human capital cost involved in such a system migration. The investment in software selection, testing and verification, process development, installation and training of personnel are not insignificant when proposing a software system conversion.

[1] Staff/1900, Stevens/11.

**Q. Please respond to Staff's[2] recommendation that the Company present evidence either here or in its next general rate case showing that the use of the SAE "XHeat" and "XCool" variables add a sufficient level of explanatory power above more transparent weather variables to justify their use.**

A. While the Company always strives to simplify its models and modeling approaches where possible, the Company is concerned that removing the SAE framework from its models would deprive its forecast of relevant knowable information regarding changes in residential usage that cannot be explained by simpler weather variables.

For example, the Company's residential survey showed that the number of homes in the Company's service territory with central air conditioning has increased by 12 percent from 2019 to 2021. Additionally, the number of homes cooled by heat pumps has increased by 2 percent over this same timeframe. While these rapid investments in cooling equipment may be driven by increasing temperatures, they have an additive effect on residential customer usage that cannot be explained by simple temperature variables alone.

Further, the SAE framework utilizes information from the Company's biannual residential survey combined with information from the U.S. Energy Information Administration regarding the impact of future changes in appliance efficiency regulations to project the impact of these regulations on residential-usage-per customer and should be retained.

[2] Staff/1900, Stevens/11.

**Q. Please respond to Staff's[3] recommendation that in PacifiCorp's next Oregon rate case the Company should use a software which allows for differencing of models or present evidence for each of their models justifying the differencing, or lack thereof, for each model.**

A. The current software used by the Company, produced by Itron, is used by approximately 150 utilities and has been used by the Company since 2008. Since that time, the forecasts produced by the Company have been approved by the commission in multiple proceedings without issue.

While the Company's software does not directly support differencing techniques, as a result of feedback from the Commission Staff in past proceedings, the Company has implemented a process that allows differencing to the residential customer class model.

The Company's residential use-per-customer model and the other classes use-per-day models show no signs of non-stationarity that would indicate a need for differencing.

**Q. Please respond to Staff's[4] recommendation that PacifiCorp host load forecasting workshops between now and its next general rate case to facilitate Staff and Intervenor input into these analyses.**

A. PacifiCorp welcomes input on the load forecast methodology, development and analysis. To that end, the Company is willing to host a load forecasting workshop between now and the next general rate case to facilitate Staff and stakeholder input

[3] Staff/1900, Stevens/11.
[4] Staff/1900, Stevens/11.

into the process and to discuss Staff's load forecast recommendations provided to PacifiCorp within this proceeding.

## II. CONCLUSION

**Q. What is your recommendation to the Commission?**

A. The Company believes its forecast and forecasting processes are reasonable and should be retained in this proceeding. While the Company is always interested in improving its forecasting methodologies, the sweeping changes proposed by Staff are premature and potentially unnecessary. The Company believes that workshops should help foster understanding between Commission Staff and the Company and would allow for continued incremental improvements in the Company's forecasting processes which benefits the Company, customers and other stakeholders.

**Q. Does this conclude your reply testimony?**

A. Yes.

Docket No. UE 433
Exhibit PAC/3300
Witness: Sherona L. Cheung

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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# Reply Testimony of Sherona L. Cheung

**July 2024**

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**ATTACHED EXHIBITS**

Exhibit PAC/3301—Revenue Requirement Summary

Exhibit PAC/3302—Oregon Results of Operations – December 2025

Exhibit PAC/3303—Staff Response to PAC Data Request 23

Exhibit PAC/3304—2017 FERC Audit of PacifiCorp's Compliance

**Q. Are you the same Sherona L. Cheung who submitted direct testimony in this case on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?**

A. Yes.

## I. PURPOSE AND SUMMARY OF TESTIMONY

**Q. What is the purpose of your reply testimony?**

A. The purpose of my testimony is to quantify the updates and revisions made to the Company's proposed revenue requirement in the current rate filing.

**Q. Please summarize your testimony.**

A. My testimony explains and supports the Company's revised non-Net Power Costs (NPC) base rate revenue requirement increase of $127.6 million in this general rate case (GRC)[1]. This is a decrease of $30.0 million from the non-NPC base rate revenue requirement increase amount requested in the Company's initial filing. My testimony discusses the revisions made to revenue requirement components in this modified revenue requirement, as well as addresses several proposals made by Staff of the Public Utility Commission of Oregon (Commission or OPUC) (Staff) and Alliance of Western Energy Consumers (AWEC).

## II. REVENUE REQUIREMENT

**Q. Please describe the calculation of the revised overall non-NPC base rate revenue increase.**

A. The Company's revised non-NPC base rate revenue increase of $127.6 million is calculated using PacifiCorp's 2020 Inter-Jurisdictional Allocation Protocol (2020

[1] The $127.6 million revenue requirement increase does not include the $66.0 million being requested through the new Insurance Cost Adjustment (ICA) for recovery of the liability insurance premium deferral under docket UM 2301 and on-going liability insurance premiums. If the ICA is not approved, these costs will need to be added to the Company's revenue requirement model for recovery in base rates.

Protocol) allocation methodology. As stated in my direct testimony, this rate filing was compiled using historical accounting information from the 12 months ended June 30, 2023 (Base Period), as a starting point. The historical information is then analyzed and adjusted to reflect known, measurable, anticipated changes, and to include previous Commission-ordered adjustments. Since the Company's initial filing, several changes have been made to modify the requested revenue increase. Exhibit PAC/3301 provides a summary of the Company's updated Oregon-allocated results of operations for the forecast period of the 12 months ending December 31, 2025 (Test Period or Test Year). In support of the revised calculations, Exhibit PAC/3302 incorporates revisions and updates to certain adjustments and provides updated iterations of workpapers that were previously presented in Exhibit No. PAC/1702 but now support the Company's reply revenue requirement calculations.

**Q. Please provide an overview of the revisions made to the Company's revenue requirement in this proceeding.**

A. In addition to the adjustments reflected in the Company's initial filing, several revisions or updates have been made to revenue requirement in the Company's reply filing. Each revision or update is described in more detail later in this testimony. Table 1 summarizes the impact of changes to the updated revenue requirement. Because of these revisions and updates, the Company's revenue requirement allocation model also automatically synchronized two other adjustments to account for cascaded changes in Interest Expense and Cash Working Capital calculations.

**Q. Are there revisions made to the Company's revenue requirement calculations that are not reflected in discrete adjustments described in the sections below?**

A. Yes, in addition to revised adjustments, the Company also made revisions to the rate of return assumptions used in its Jurisdictional Allocation Model (JAM). The first of these revisions reflects a reduction to the requested return on equity (ROE) as discussed in greater detail in the reply testimony of Company witness Ann E. Bulkley.

Also, cost of debt embedded in the revenue requirement calculation in this reply filing has been updated to reflect 5.28 percent as recommended by Company witness Nikki L. Kobliha in her reply testimony. The impact of all updates to revenue requirement made in reply testimony are quantified in Table 1.

**TABLE 1—Reply Revenue Requirement**

| | **$ million** |
|---|---|
| Company Filed - Non-NPC Base Request | 157.7 |
| | |
| **Adjustments to Filing** | **Total** |
| ROE Update to 9.65% | (23.5) |
| Cost of Debt Update to 5.28% | 2.7 |
| Remove Customer Service Project | (6.3) |
| Customer Payment Fees Update | (3.4) |
| Other Corrections & Updates | 0.5 |
| Total Adjustments in Reply | (30.0) |
| | |
| Company Reply - Non-NPC Base Request | 127.6 |

**Q. Please describe Exhibit PAC/3302.**

A. Exhibit PAC/3302 is the Company's Oregon Results of Operations Report (Report), revised to incorporate changes and updates outlined in the table above. The Report is

organized in a manner similar to Exhibit PAC/1702 that was provided as an exhibit with my direct testimony:

- Tab 1 (Summary) reflects the Oregon-allocated results based on the 2020 Protocol.
- Tab 2 (Results of Operations) details the Company's reply revenue requirement by Federal Energy Regulatory Commission (FERC) account and 2020 Protocol allocation factor.
- Tabs 3 through 8 and Tab R provide supporting documentation for adjustments that have been revised in the calculation of the Company's reply revenue requirement.

Only adjustment and support pages originally included in Exhibit PAC/1702 that have changed since the Company's direct filing are included in Exhibit PAC/3302. For any pages not modified since the Company's direct filing, the original page as presented in Exhibit PAC/1702 continues to be an appropriate reference.

## III. DESCRIPTION OF UPDATED & OTHER PROPOSED ADJUSTMENTS

### A. TAB 3 - Revenues

**Q. Has any party proposed revisions to the Company's filed revenues in this GRC?**

A. No, there are no proposed revisions to revenues as filed in the Company's direct filing in this case. Staff witness David Abraham summarized Staff's review of the Company's reported Other Operating Revenues in this case and does not recommend any changes at this time.[2]

[2] Staff/400, Abraham/7.

**Q. Has the Company's revised any of its proposed revenue adjustments in its reply filing?**

A. Yes. Adjustment 3.4, Fly Ash Revenue was updated to reflect changes to forecasted levels of Fly Ash Revenues for calendar year 2025 to synchronize underlying generation assumptions with the updated NPC forecast to reflect the settlement outcome of the 2025 Transition Adjustment Mechanism (TAM) in docket UE 434. The revenue requirement of this update is approximately $269,000.

## B. TAB 4 – Operation & Maintenance (O&M) Expense

**Q. What adjustments or revisions is the Company making in Tab 4, Operation & Maintenance Expense, for its reply filing?**

A. The Company has made revisions or updates to the following adjustments, discussed in more detail below in my testimony.

- Adjustment 4.2, Confidential Wage & Employee Benefits Adjustment
- Adjustment 4.7, Revenue-Sensitive Items & Uncollectible Accounts
- Adjustment 4.9, Meals and Entertainment Adjustment
- Adjustment 4.10, O&M Expense Escalation
- Adjustment 4.12, Customer Payment Fees

***Adjustment 4.2, Confidential Wage & Employee Benefits***

***a. Wages, Salaries and Employee Benefits***

**Q. Has the Company modified the methodology it uses to escalate wages and salaries for the Test Period?**

A. No. The Company has not changed the methodology by which wages and salaries are escalated for the Test Period in this case. Staff witness Steph Yamada outlined Staff's

review of Test Year wages and salaries and recommended no further adjustment to non-union salaries and wages, and overtime. However, Staff recommended that union wages be updated to reflect actual negotiated union wage increases for the Test Year if those amounts become known during the course of this proceeding.[3] At the time the Company's reply filing was prepared, one of the two collective bargaining in negotiation has finalized, while the other is still in negotiation. The finalized increase is for IBEW Local 659, and the finalized increase matches the projected change reflected in the Company's direct filing. Therefore, there is no incremental change necessary to Test Year union wages at this time. Should IBEW Local 77 also arrive at an agreed upon increase percentage during the pendency of this case, the Company agrees to update the projected increase to reflect the finalized amount.

**Q. Has the Company made changes to Adjustment 4.2?**

A. Yes. During the Company's initial filing a few labor expense general ledger (G/L) Accounts were not picked up in adjustment 4.2 due to a formula error. The Company has corrected the issue to pick up all G/L accounts making up labor dollars expensed in the base year. The correction results in an increase of a little over $8,000 to test period wages and salaries expense on an Oregon-allocated basis.

Additionally, Staff witness Nicola Peterson proposed a reduction of approximately $1.2 million on an Oregon-allocated basis to reflect a reduction to the escalation assumption to medical benefits assumed in the Company's filing from eight percent to six percent. Staff found six percent to be more appropriate as it is consistent with industry trends. Peterson cited the PricewaterhouseCoopers Health

[3] Staff/2000, Yamada/6.

Research Institute forecasts of health care costs, which reports anticipated increase by seven percent in 2024, and the Peterson Center on Healthcare and Kaiser Family Foundation, which predicts health care costs to rise by five percent in 2024.[4] As I explain below, the Company accepts this adjustment with corrections.

**Q. Have you reviewed the calculations supporting Staff witness Peterson's proposed adjustment?**

A. It did not appear that Staff witness Peterson sponsored any specific exhibits supporting the proposed adjustment, nor were any workpapers supporting the proposed adjustment provided to the Company. However, I was able to examine Staff witness Itayi Chipanera's workpaper supporting Staff exhibit 200, Staff's revenue requirement model which included a tab labelled "1600-Peterson" where the calculation to a "Payroll Overhead" adjustment can be found. While the Staff proposed medical benefit expense figure was hardcoded in Chipanera's workpapers, the Company was able to recreate the calculation of the "$61,326" (thousand) presented as Staff's recommended medical benefit expense amount by taking the Base Period medical benefit expenses of approximately $57.9 million provided in the Company's response to OPUC Standard Data Request (SDR) 63 and apply a six percent increase to arrive at Staff's proposed "$61,326" thousand, or approximately $61.3 million. Staff then compared this $61.3 million figure against the Company's proposed Test Year medical benefits expense in its direct filing to confirm Staff's proposed adjustment of approximately $1.2 million. Staff then modelled this $1.2

[4] Staff/1600, Peterson/14.

million as a reduction to Oregon-allocated medical benefit expenses in its revenue requirement model.

**Q. Are there any issues with Staff's calculation of the proposed adjustment to medical benefits expenses?**

A. Yes. There are two main issues with the adjustment as it has been calculated and modelled by Staff. Firstly, the decremental adjustment of $1.2 million to medical benefits expense calculated by Staff was derived by comparing the total-Company Test Year expense against a revised Test Year expense calculated by escalating the also total-Company base year expense provided in OPUC SDR 63 by six percent. Accordingly, the $1.2 million reduction to expense calculated by Peterson is a total-Company figure, which was modelled through Staff's revenue requirement model as if it were an Oregon-allocated amount. By not applying a jurisdictional allocation to the proposed total-Company adjustment before flowing it through the revenue requirement model, the reported impact on revenue requirement in this case of the proposed adjustment is artificially inflated.

Further, medical expenses are incorporated into Test Year results as a part of Adjustment 4.2 - Confidential Wage and Employee Benefits. Total Company expenses reflected in Adjustment 4.2 are then spread across Federal Energy Regulatory Commission (FERC) accounts by using the approximated labor expense split from the Company's most recently available FERC Form 1 filing, where approximately one-third of projected total-Company expense adjustment to labor costs are excluded from the case based on capitalization assumptions built into Adjustment 4.2. Properly taking into account this exclusion for labor costs assumed to

be capitalized and not adjusted for in Adjustment 4.2, which would further reduce the impact of the proposed $1.2 million reduction of total-Company on the case.

**Q. Does the Company accept Staff's adjustment?**

A. Yes, but with corrections. The Company is agreeable to a reduction of medical benefits expenses escalation from eight percent as filed to six percent as proposed by Staff as the Company has since reviewed healthcare cost projections and agrees that current forecasts reflect projected increases more in line with a six percent escalation. However, Peterson's calculation of the reduction is flawed and will need to be recalculated to properly reflect the impact of jurisdictional allocations and capitalization exclusions.

**Q. Please describe the Company's update to medical benefits.**

A. Properly flowing the updated escalation assumptions through Adjustment 4.2, once the total-Company expenses are spread across FERC accounts, with capitalization assumptions applied, jurisdictional allocation factors as calculated in this proceeding in accordance with the 2020 Protocol are then applied to each FERC account balance to quantify Oregon's share of the total-Company medical benefit expense. The resulting impact of this change is an expense reduction of approximately $212,000 on an Oregon-allocated basis.

***b. Bonuses***

**Q. Does Staff make any proposed changes to Bonuses?**

A. Yes. Staff witness Yamada believes that the Company has not adjusted its Test Year proposal to account for the exclusion of merit-based Bonuses, which Staff interprets as approximately $1.9 million at the total-Company level, representing a five-year

historical average of actual bonuses attributable to non-officer employees, presumably referencing Exhibit PAC/1702, Cheung/78. Specifically, Staff points to the bonus category of expenses as inappropriate to include in rates because bonuses include what Staff considers "merit-based" awards, such as amounts awarded under the STARS Program, as well as cash performances periodically granted to reward the accomplishment of significant non-recurring tasks or projects. Based on this belief and interpretation, Staff proposes a 50 percent reduction, in the same manner as the annual incentive program (AIP), of the $1.9 million of Bonuses included in the Company's direct filing resulting in a reduction of Test Year bonuses of approximately $930,000 at the total-Company level.

**Q. Does the Company agree with Staff witness Yamada that no adjustment to bonuses had been made in this case?**

A. No. The Company has in fact already incorporated an adjustment to bonuses, along with AIP amounts proposed for recovery in this rate case.

**Q. Please describe how the Bonus amounts are derived in the Company's direct filing?**

A. The Company reviewed its AIP percentage relative to total eligible wages over five historical years from 2018 to 2022. Parsing out the portion of Bonus amounts that should be included as part of each year's AIP amounts and adding it to the AIP recorded to Incentives (less Named Executive Officers (NEO) share), the Company calculated the percentage of total AIP relative to exempt wages for each historical year. From there, the Company calculated the five-year historical average percentage of 14.781 percent and applied that to Test Period exempt wages to arrive at the total

expected Test Year AIP in 2025 of $33.4 million on a system-wide basis. The Company then applied a 50 percent reduction to this calculated Test Period non-officer AIP, to arrive at a total of $16.7 million in Test Period AIP to be included in this case.

Similarly for Bonuses, the Company performed a similar averaging calculation based on the recorded Bonus, reduced by the amounts that should be included as part of each year's AIP amounts, as described above. The remaining balance in this Bonus account reflects safety awards, hire-in bonuses, referral awards, training awards, and other amounts that do not fit the description of a "merit-based" incentive or bonus that would be subject to a 50 percent sharing provision. Based on a five-year average of Bonus amounts, excluding amounts more appropriately considered as "merit-based" compensation like AIP, the average level of Bonus expense is approximately $1.9 million on a system-wide basis, as shown in Exhibit PAC/1702, Cheung/78 as the five-year average of "Bonus and Awards" included in this case. In other words, the $1.9 million amount already reflects the exclusion merit-based bonuses, and is not, as Staff interprets, *total* five-year historical average of actual bonuses attributable to non-officer employees. This method is consistent with the methodology used and adopted into rates in the Company's last Oregon rate case, docket UE 399.

**Q. Is there a way to confirm that the Bonus amounts used to calculate the five-year historical average included in the Test Year is not the total Bonus expenses, but have in fact been reduced for merit-based amount exclusions?**

A. Yes. One could compare the annual Bonus and Award amounts listed on Exhibit

PAC/1702, Chueng/78, to the annual Bonus amounts reported in the Company's response to OPUC SDR 92, and see that the amounts included in Exhibit PAC/1702 are lower than the amounts reported in OPUC SDR 92. Correspondingly, the annual AIP amounts presented in Exhibit PAC/1702, Cheung/78, is also higher than the reported amounts in OPUC SDR 92 for each corresponding year. This reflects the Company's effort to parse out merit-based Bonuses to be included in the calculation of the 50 percent disallowance by adding that balance back to the AIP amounts reported each year. The Company presented this explanation in its response to OPUC Data Request 233.

**Q. Is Staff's proposed Bonus adjustment warranted?**

A. No. The Company's proposed calculation of labor expenses already properly removes 50 percent of AIP, and merit-based components of Bonus expenses from Test Year projections. The only bonus amounts that remain in the Test Year is $1.9 million of bonus expenses that represent bonus categories that have been consistently included as was the case in docket UE 399.

***c. Annual Incentive Program***

**Q. Does Staff make any proposed changes to AIP?**

A. Yes. Staff identified, that while the 2018-2022 figures used to calculate the five-year historical average AIP percentage of 14.781 percent appear to accurately reflect Base Salaries & Wages attributable to Exempt employees only, the 2025 Test Period wage total of $225.9 million to which the historical AIP percentage was applied to extrapolate total Test Year AIP incorrectly included wages attributable to both Exempt employees and Officers. AIP should only include Exempt employees as

officer incentives are not recoverable in rates. Staff proposes taking the OPUC SDR 92 "Exempt employee Base Salaries & Wages" figure of $221.9 million and applying the calculated five-year historical average of 14.781 percent to that figure, to calculate the Test Year AIP amount to which a 50 percent reduction should be taken. This correction would result in Test Year AIP includable in rates of $16.4 million on a total-Company basis, in comparison to the $16.7 million of Test Year AIP in rates included in the Company's direct filing.

**Q. Does the Company agree with the changes described above to AIP?**

A. Yes. The Company agrees the Test Year wage total used as the basis to calculate Test Year AIP should only reflect the exempt employee wages. However, in Staff's workpaper, the proposed reduction to Bonus and AIP results a total Oregon-allocated adjustment of $353,000, with $223,000 of the reduction applied to expenses, and $130,000 of the reduction applied to capital. As discussed above, the Company disagrees with the Bonus portion of this proposed adjustment, but additionally, in GRCs, the Company does not adjust the capitalized components of labor expenses in its Wages & Employee benefits adjustment. Therefore, there should be no reduction necessary for the portion of the AIP adjustment presumed to be capitalized, as that cost was not reflected in the Company's direct filing to begin with. By revising the Test Year wage basis on which Test Year AIP is calculated as described by Staff, and properly flowing through jurisdictional allocation and capitalization exclusion impacts, the Company determined that the impact of this correction is approximately $199,000 reduction of Test Year labor expenses on a total-Company basis, which translates to approximately $57,000 on an Oregon-allocated basis.

**Q. Did Staff witnesses review any other wages and employees benefits related items in this filing?**

A. Yes. Staff witness Yamada provided an overview of Staff's review of the Company's full-time equivalent levels, and directors fees and expenses and recommended no adjustments at this time.

**Q. Do you address Staff's proposed adjustment to capitalized officer incentives?**

A. Yes. This adjustment will be addressed in section Tab R, under Adjustment R_1, Capitalized Incentives Adjustment.

***Adjustment 4.7, Revenue-Sensitive Items & Uncollectible Accounts***

***a. OPUC Fees***

**Q. Were changes to revenue-sensitive items proposed by Parties in this case?**

A. Yes. As acknowledged in my direct testimony, the Company submitted its direct filing with an OPUC fee percentage of 0.43 percent, as published by Order No. 23-057 in docket UM 1012, because the 2024 update was released after the Company's filing in this docket made on February 14, 2024. Accordingly, as recommended by Staff witness Itayi Chipanera, the Company has updated the OPUC fee to reflect in its revenue requirement calculation the latest approved fee percentage of 0.45 percent, as approved by Commission Order No. 24-054, issued February 22, 2024. The impact of this update to revenue requirement in reply is approximately $87,000.

**Q. Why is the estimated revenue requirement impact different from Staff's estimate in Exhibit Staff/200, even though both Staff and the Company are making the same revision to OPUC fees?**

A. On tab "200-Chipanera" of Exhibit Staff/200 "Work Paper Revenue Requirement Model" where the impact of the OPUC fees change is quantified, the workpaper only provided a hardcoded figure. However, I suspect Staff's calculation only quantified the impact of the updated fee percentage on the Company's proposed price change within the revenue requirement model, and neglected to capture the corresponding impact of updating the OPUC Fees on test year revenues before the price change as reflected in Adjustment 4.7 in Exhibit PAC/1702.

***b. Uncollectible Expenses***

**Q. Were there other adjustments proposed to revenue-sensitive items and uncollectible expenses in this case?**

A. Yes. Staff witness Bret Farrell proposes a three-year average methodology for uncollectible expenses wherein three years of historical uncollectible expense (2020-2022) are averaged to establish amounts to be recovered in customer rates in the Test Year. Staff's proposed methodology would result in an uncollectible rate of 3.42 percent, as opposed to the Company proposed historical-based uncollectible rate of 6.14 percent. This adjustment would reduce the uncollectible expense in the Test Year from the Company's proposed $10.5 million to approximately $5.7 million.

**Q. How is uncollectible expense calculated in the Company's filing?**

A. Uncollectible accounts expense is adjusted to the Test Period level by applying the Base Period historical uncollectible rate (Oregon uncollected accounts expense in

FERC Account 904 divided by Oregon general business revenues for the 12 months ended June 2023) to the normalized general business revenues in the Test Period.

**Q. What explanation did Staff provide in support of a three-year averaging methodology for uncollectible expenses?**

A. Staff's basis for proposing a three-year averaging methodology for uncollectible expenses is three-fold. Staff first claims there is a "long-standing policy of Commission Staff to apply a three-year average methodology to determine the Test Year uncollectible expense for a utility's revenue requirement," Staff cites to several orders from general rate proceedings for Avista Corporation (Avista), Idaho Power Company, and Cascade Natural Gas Corporation adopting stipulations in which uncollectible expenses were calculated using a multi-year average.[5] Staff witness Farrell further states that Staff's primary concern with the Company's proposed methodology is that it relies solely on data from one year, and that using only a single year of data to estimate the Test Year uncollectible rate is overly simplistic, which can reflect non-normal events within that year, and fails to consider broader patterns or trends in the uncollectible rate within the Company's Oregon service territory. Finally, Staff accuses the Company of having failed to adequately justify the use of this methodology by providing historical evidence to support the accuracy of this approach.

**Q. Is a three-year averaging methodology used as the exclusive methodology to establish customer rates in prior rate cases?**

A. No. While there are instances where a three-year average of expenses has been agreed

[5] Staff/900, Farrell/3 n.1.

upon in settlement to establish recovery levels of uncollectible amounts in rate cases, it is not the exclusively used method. Staff cites cases adopting a four-year average and a non-consecutive three-year average with an anomalous year removed.[6] Recently, Portland General Electric Company (PGE) and Northwest (NW) Natural have proposed to calculate uncollectible expense using a forecast rather than historical data.[7] NW Natural's request is pending, and PGE settled at an uncollectible rate that was higher than the three-year average supported by Staff.[8] It is also important to note that the Commission has adopted these stipulations but has not specifically determined that a three-year historical average should be the standard method for calculating uncollectible expense. Moreover, uncollectible rates are unique to each individual utility based on a myriad of circumstances, and the fact that some utilities have agreed in settlement to use a three-year average does not mean that this approach is appropriate for PacifiCorp.

**Q. Has PacifiCorp historically used a three-year average approach to calculate uncollectible expense in rates?**

A. No. For well over a decade, PacifiCorp has relied on Base Period actuals, rather than an averaging methodology.[9] Most recently, in docket UE 399, Staff recommended that PacifiCorp use the uncollectible rate of 0.336 percent established in the

[6] Staff/900, Farrell/3 n.1.
[7] *In re NW. Natural Gas Co. Request for a General Rate Revision*, Docket No. UG 490, NW Natural/1300, Wilson-Sparley (Dec. 29, 2023); *In re Portland Gen. Elec. Co. Request for a General Rate Revision*, Docket No. UE 416, PGE/900, Lynn-Nestel/16 (Feb. 15, 2023).
[8] Docket No. UE 416, Order No. 23-386 at 8 (Oct. 30, 2023).
[9] *See In the Matter of PacifiCorp, dba Pac. Power's Request for a Gen. Rate Revision*, Docket No. UE 246, PAC/1100, Dalley/20 (Mar. 1, 2012) ("Uncollectible accounts expense is adjusted to the Test Period level by applying the historical uncollectible rate (Oregon uncollectible accounts expense in FERC Account 904 divided by Oregon general business revenues) to the normalized general business revenues in the Test Period.").

Company's previous rate case (UE 374), which predated the onset of Covid-19.[10] PacifiCorp's experience is not consistent with Staff's claim in this case that the three-year methodology is a "long-standing" Staff policy.

**Q. Does the range of 2020-2022 proposed by Staff for use in a three-year average provide a reasonable basis for establishing an uncollectible rate in this case?**

A. No. Calendar years 2020, 2021 and 2022 were unprecedented years marked by economic disruption related to the Covid-19 pandemic. In addition, the Commission adopted revised Division 21 rules in late 2022, which significantly changed the collections process, and the effects of these new rules in the Test Year will not be captured in Staff's three-year average. In PacifiCorp's last rate case, Staff advocated *against* using 2021 data to establish the uncollectible rate, stating "It does not seem reasonable to Staff to utilize uncollectible account data from a time period that includes a once in a century global pandemic in the proposed Test Year."[11] Staff specifically noted the Arrearage Management Programs and other factors that Staff expected may differ between the pandemic period and the 2023 test year in that case. But Staff now takes the contradictory position that it is appropriate to set PacifiCorp's uncollectible rate using pandemic-period data.

**Q. Even if a three-year methodology were appropriate, is Staff's calculation of the proposed three-year average uncollectible expense accurate?**

A. No. Staff's adjustment calculates an uncollectible rate using "net write-offs" divided by each calendar year's Oregon retail revenues, while the uncollectible rate as

[10] *In the Matter of PacifiCorp, dba Pac. Power's Request for a Gen. Rate Revision*, Docket No. UE 399, Staff/1100, Fjeldheim/14 (June 22, 2022).
[11] Docket No. UE 399, Staff/1100, Fjeldheim/14.

approved in past GRCs are calculated by uncollectible expense (FERC Account 904 expense) balance divided by general business revenues. Uncollectible expense is not synonymous with "net write-offs". FERC Account 904 (Uncollectible Expense) balances include write-offs, recoveries, and the bad debt provision related to retail, transmission and joint use customers. In other words, write-offs are just a subcomponent of total reported uncollectible expense. Adjusting for Staff's misunderstanding on the nomenclature, the uncollectible rate (properly calculated as FERC Account 904 expense divided by general business revenues) for each referenced calendar year is presented in Table 2 below, with comparison to each year's rate reflected in Staff witness Farrell's proposed calculations:

**TABLE 2—Historical Uncollectible Rate Comparison**

| | 2020 | 2021 | 2022 | Average |
|---|---|---|---|---|
| Staff Exhibit 902 (Net write-offs/Retail Revenues) | 0.189% | 0.284% | 0.551% | 0.342% |
| PacifiCorp Results of Operations (Uncollectible Accounts/General Business Revenues) | 0.514% | 0.440% | 0.626% | 0.527% |

As shown in Table 2 above, Staff's calculated "uncollectible" rate is consistently lower than the Company's reported uncollectible rate for each calendar year because Staff's calculation only reflects "net write-offs" and therefore is an incomplete calculation of uncollectible accounts in any given year.

**Q. Please summarize your recommendation regarding Staff's proposed adjustments to uncollectible accounts in this case.**

A. Staff's proposal of a three-year average uncollectible rate is inappropriate and inconsistent with the Company's approved uncollectible rates in previous GRCs.

Furthermore, in calculating a three-year average "uncollectible rate", Staff incorrectly only calculated the rate using "net write-offs", rather than the true reported FERC Account 904 uncollectible expenses, which resulted in Staff's proposed uncollectible rate to be grossly understated. Finally, years 2020 through 2022 uncollectible expenses are not an appropriate baseline to be used in establishing uncollectible expenses into the Test Year because those three years in particular reflect uncollectible account balances that are impacted by the Covid-19 pandemic. Ultimately, as Staff witness Farrell noted, "[E]ffectively, the Company is using the most recently available data to calculate an uncollectible rate and using that as their Test Year estimate."[12] This reflection of most recently available data is most representative of the Company's anticipation of operational conditions into the Test Year.

***Adjustment 4.9, Meals and Entertainment Adjustment***

**Q. Did any party propose revisions to the Company's proposed Meals and Entertainment adjustment?**

A. Yes. Staff proposes an incremental adjustment for meals and entertainment (M&E) expenses relating to catering, on-site meals and refreshments, and Coffee/Water/Beverages categories, where in addition to the M&E categories of expenses already removed in the Company's direct filing, 50 percent of Base Period expenses in these three additional categories would be subject to exclusion from rates.

**Q. How did Staff determine that this adjustment was necessary?**

A. Staff reviewed the Company's proposed adjustment 4.9, in Exhibit PAC/1702, as well

[12] Staff/900, Farrell/4.

as the Company's response to OPUC SDR 57 to identify any O&M non-payroll discretionary expenses that appear to be excessive, without sufficient business purpose, or not related to the provision of safe and reliable energy to customers. From the 94 spreadsheets of Excel workbooks provided by the Company in response to OPUC SDR 57, Staff filtered the data by transaction descriptions and account number names, to further examine selected expenditure types, including Catering Services (non-Employees), On-site Meals & Refreshments, Gifts, Airfare, Travel, as well as Coffee/Water/Beverage Services to determine whether each expenditure type benefited customers, or are discretionary and should be shared between customers and shareholders according to Commission policy. Based on this review, Staff identified additional base year expense of approximately $153,000 of Oregon-allocated non-payroll O&M expense in the Base Period that is deemed eligible for a 50 percent sharing provision, citing docket UE 197, a PGE GRC, where the Commission agreed with Staff that "the costs for food and gifts are discretionary and should be shared equally by ratepayers and shareholders."[13] The amounts identified by Staff by category as follows:

**TABLE 3—Incremental M&E Expenses Subject to Sharing (Exhibit Staff/1803)**

| Expenditure Category | G/L Account | OR-Alloc. O&M |
|---|---|---|
| Catering Services – Non-Employee | 530035 | $8,690 |
| Coffee/Water/Beverage Services | 503430 | $5,410 |
| On-Site Meals & Refreshments | 503115 | $139,124 |
| Total Expenses subject to sharing | | $153,224 |

[13] *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, Docket No. UE-197, Order No. 09-020 at 21 (Jan. 22, 2009).

**Q. Do you have any concerns with Staff's review of these costs?**

A. I attempted to recreate Staff witness Paul Rossow's review to replicate the amount of expenses incremental to the Company's proposed adjustment in its direct filing identified as subject to sharing and was unable to arrive at the dollar amounts proposed by Staff witness Rossow. In reviewing Staff's exhibit, the source of several hardcoded numbers was not immediately evident. The lack of formulas in the workpaper made the review challenging. In response to the Company's data request regarding this issue, Staff responded that the hardcoded numbers came from a pivot table in a separate confidential Staff workpaper with specific accounts filtered. The lack of clear formulas in Staff's workpaper in this matter impacted the Company's ability to review Staff's proposed adjustment.

After reviewing available workpapers in conjunction with Staff's response to PAC Data Request 18, the Company was able to determine that transaction records Staff witness Rossow filtered out of the Company's response to OPUC SDR 57 may not be complete, in that not ALL eligible non-labor O&M expenses recorded to G/L accounts as identified in the table above are reflected in Staff's analysis. At the same time, there were also instances where the same transaction item was erroneously included twice, while some other expenses recorded to Work Orders that ultimately credited out of the account category were also included in Staff's adjustment such that the recording of the expense was flagged for the 50 percent reduction, but the transaction where the amount settled out of the category was not. Due to these observed issues, I recreated the analysis with balances for the Base Period for the three specific cost categories identified by Staff, properly considering any offsetting

amounts and re-extracting the underlying accounting data from the Company's accounting system for the Base Period. I found the balances by category as Staff identified for further adjustment should be as follows:

**TABLE 4—Staff Identified Incremental M&E Expenses Corrected**

| Expenditure Category | G/L Account | OR-Alloc. O&M |
|---|---|---|
| Catering Services – Non-Employee | 530035 | $3,081 |
| Coffee/Water/Beverage Services | 503430 | $5,770 |
| On-Site Meals & Refreshments | 503115 | $148,865 |
| Total Expenses subject to sharing | | $157,716 |

**Q. Does the Company agree with the adjustments proposed by Staff?**

A. Partially, in principle. The Company accepts Staff witness Rossow's proposed adjustment relating to expenses in the Catering Services and On-site Meals and Refreshment category as those expenses appear to fall within the spirit of the established Commission precedential adjustments intending to have the costs of food and gifts deemed discretionary be shared between shareholders and customers, but rejects the proposed adjustment for expenses recorded in the Coffee/Water/Beverages category. The Company views expenses related to coffee, water and beverages as standard, common, business expenses, providing employees with basic hydration options during work hours, and elects to exclude those expenses from the adjustment. The Company also notes that an annual expense of $5,700 on an Oregon-allocated basis (which is less than $16 per day for a company of almost 5,000 employees) spent on coffee and water keeping employees functional and operating efficiently does not appear to be "excessive, [or] without sufficient business purpose", as described as the purpose for which expenses are being subjected to sharing provisions by Staff witness Rossow.

The Company further excluded storm and fire restoration work-related amounts in the identified categories from the adjustment, consistent with how the M&E expense adjustment has been calculated in past cases and in the Company's direct filing, as providing meals during emergency situations like storm and fire restoration efforts is critical in facilitating efficient and prompt reconnection of electric service to customers, which the Company does not consider "discretionary". With these revisions, the Company has incorporated in its reply filing an additional non-labor O&M expense adjustment to reduce expenses from specific M&E categories based on Oregon-allocated expense amounts identified as follows:

**TABLE 5—Incremental M&E Expenses Subject to Sharing in Reply**

| Expenditure Category | G/L Account | OR-Alloc. O&M |
|---|---|---|
| Catering Services – Non-Employee | 530035 | $3,081 |
| On-Site Meals & Refreshments | 503115 | $128,748 |
| Total Expenses subject to sharing | | $131,978 |

Based on the Company's analysis of G/L Account 530035 (Catering Services – Non-Employees) and G/L Account 503115 (On-Site Meals & Refreshments) expenses recorded in the Base Period and excluding the Coffee/Water/Beverage Services (G/L 503430) category, or amounts related to fire and storm restoration work within these categories, the Company reflected an incremental reduction of approximately $66,000 to M&E expenses.

***Adjustment 4.10, O&M Expense Escalation***

**Q. Did the Company revise Adjustment 4.10 – O&M Expense Escalation?**

A. Yes. Adjustment 4.10 was updated for downstream effects of other revisions made to other O&M adjustments in this reply filing. The impact of the update is minor, at approximately $10,000 reduction to revenue requirement.

*Adjustment 4.12, Customer Payment Fees*

**Q. Has the Company incorporated any revisions to Adjustment 4.12 in its reply filing?**

A. Yes. As discussed in the reply testimony of Company witness Robert M. Meredith, the Company agrees with using a three-year average for the pay station and card payment counts as proposed by Staff. The Company also agrees with Staff that the Base Period expense on which the Company based its adjustment in its direct filing did reflect some inaccuracies. Accordingly, the Company included in this reply filing the corrected data for 2023 and the inclusion of a three-year average methodology in calculating the impact to revenue requirement of eliminating payment fees for customers. With correction and update as discussed in Company witness Meredith's testimony, the net change to Test Year revenue requirement in this case is decrease of $3.4 million.

***Other Proposed O&M Adjustments***

***a. Insurance Expense***

**Q. Has any party proposed adjustments to insurance expenses?**

A. Yes. Staff witness Peterson is recommending that the Company "normalize" the expense by removing one "substantial" cash payment associated with a specific fire event from the three-year average liability expense used to establish annual injuries and damages accrual levels in rates for Oregon customers.

**Q. Please reiterate the purpose of establishing injuries & damages accrual levels in rate filings on a three-year historical average basis.**

A. The purpose of averaging expenses in a rate proceeding, is to normalize spikes and

dips in historical data that do not follow a consistent trend but can fluctuate significantly from year-to-year, recognizing that those spikes and dips are a given in the normal course of business. The idea is that by pooling more data points, and taking an average, erratic movements that cannot fully be anticipated or expected to perpetuate year-over-year can be smoothed out. Due to the unpredictable nature of these injuries and damages expenses, the Company has used a three-year average calculation to set a normalizing level of these costs to be recovered in the Test Period. This methodology is consistent with the adopted methodology in the Company's most recently approved GRC, docket UE 399, used to set injuries and damages expense levels in rates.

**Q. Does the three-year average cash payment the Company used to establish its three-year average calculation represent costs associated with specific injuries and damages events?**

A. No. The Company is not asking for recovery of specific cash payments but is instead using those historic amounts to develop a normalized level in the Test Period. The cash payments that are used in the calculation of the three-year average in the Test Period have already been paid out and are historic payments from previous years.

**Q. Did the Company use a three-year average cash payments (net of reimbursements) to calculate the injuries and damages expense accrual level in the previous rate case filing?**

A. Yes. In the Company's last rate case filing, docket UE 399, the Company included a three-year average of historical gross expense net of insurance proceeds using the cash method. The Company used the same method in this rate case filing.

**Q. What is your recommendation on Staff's proposed adjustment for this one cash payment to injuries and damages expense?**

A. I recommend Staff's recommendation be rejected, and the three-year average level including all cash payments as filed in the Company's direct testimony be maintained. The Company's proposed methodology in this rate case is consistent with the approved methodology in its previous GRC. Furthermore, the objective of establishing an annual accrual level of injuries and damages expense recovery in rates using a historical average is to levelize the impacts of spikes and dips due to the unpredictable nature of insurance events, while ensuring recovery levels continue to be sufficient to cover these types of expenses over time. Removing a specific payment due to the magnitude of the payment is counter to this objective and defeats the purpose of the average calculation.

**Q. Did Staff make additional recommendations to revise injuries and damages expenses in this case?**

A. Yes. Staff witness Peterson proposes a further adjustment to reduce the FERC Account 925 expenses to reflect a three-year averaging of legal fees.

**Q. Did Staff witness Peterson describe in testimony reasons in support of this adjustment?**

A. No specific reasons were included in testimony on why this adjustment should be included in this rate case filing. In testimony Staff witness Peterson stated, "Staff has requested more detail on the breakdown of the legal fees, but at this time, Staff is also recommending reducing legal fees to a 3-year average."[14] Staff witness Peterson

[14] Staff/1600, Peterson/22.

commented that the data request seeking additional legal fees information had not been received by the time Staff's testimony was drafted.[15] The Company reviewed the history of responses to data requests in this docket and believes this statement is in reference to OPUC Data Request 601. The Company was able to confirm that its response to OPUC Data Request 601 was submitted no later than June 7, 2024, which would have been just about three weeks prior to Staff's testimony filing date.

**Q. Does the Company agree with the adjustment proposed by Staff to reduce the legal fees in FERC Account 925 to a three-year average?**

A. No. The Company does not agree with the adjustment proposed by Staff to reduce the legal fees in FERC Account 925 to a three-year average.

**Q. In previous rate cases approved by the Commission, has the Company used an average calculation to develop the legal fee amount included in FERC Account 925 for the Test Period?**

A. No, the Company has not averaged the legal fee amount in previous rate cases. In this rate case filing, the Company has followed the same treatment as previous rate cases for the legal fees included in the Test Period.

**Q. Why does the Company not agree with this adjustment?**

A. An average calculation can be useful for categories in which the amounts fluctuate up and down over the years but does not follow any predictable pattern. In the case of legal fees recorded into FERC Account 925, the amounts have been steadily increasing, not fluctuating up and down. The Company believes that the legal fee amount included in the Base Period, which is the most recent reporting period data

[15] Staff/1600, Peterson/22.

available at the time this filing was prepared, would be more representative of the anticipated level of legal fees in the Test Period. A three-year average would not reflect expense into the Test Year consistent with the most currently available established levels, as legal fees have been trending upwards consistently over the past three years.

**Q. What are some of the reasons legal fees are increasing?**

A. As discussed in the Company's response to OPUC Data Request 601, it is difficult to identify a single element or driver that determines yearly changes in legal fees. It is subject to a number of variables including, but not limited to, the amount of ongoing litigation, schedules of proceedings as determined by various courts and administrative agencies, and the amount of legal work to support various transactions that the Company is involved in.

**Q. Please summarize your recommendations with regards to injuries and damages provision accruals and legal fees in this case.**

A. The Company recommends that the approved methodology to establish injuries and damages provisions accrual in rates adopted in docket UE 399 be upheld. A three-year averaging methodology smooths out the impact of large payments that have a tendency to fluctuate and cannot be predictably timed, while assuring that over time, recovery amounts sufficiently cover necessary payments. The Company also recommends using actual legal expenses as the basis to establish Test Year FERC Account 925 expenses, as opposed to a three-year average. This best reflects the most current expectations of legal expense levels going into the Test Period, since legal

fees have clearly been following an increasing trend and is not erratically fluctuational in nature.

***b. Memberships and Subscriptions***

**Q. Does the Company agree with Staff's proposed adjustment to memberships and subscription in this case?**

A. No. The Company disagrees with adjustment proposed by Staff witness Rossow to memberships and subscription expenses. In addition to the adjustment for this expense item included in my direct testimony, Adjustment 4.8 – Memberships and Subscriptions[16], Staff is proposing a full disallowance of trade and economic-related memberships, resulting in a reduction to revenue requirement in this case by approximately $28,000.

**Q. Please describe Staff's position on this issue.**

A. Staff indicates that the Commission's historical treatment of memberships, dues and donations determined that expenses of this nature that are not necessary for utility service, primarily to promote the company within the community, not to benefit ratepayers, or not recoverable in rates if done by the utility itself are not appropriate to include in a utility's revenue requirement. To limit the amount that ratepayers fund for activities that fall within the categories listed above, Commission practice is to exclude membership expenses related to economic development and civic organizations and to exclude a percentage of membership costs for trade organizations, unless the utility can present a convincing argument that the membership is necessary for utility service or otherwise a benefit to ratepayers.

[16] Exhibit PAC/1702, Cheung/103-105.

**Q. How has the Company historically treated membership dues in GRCs?**

A. The Company has consistently included 75 percent of annual membership and subscription expenses in rates. This practice has been used since the stipulated outcome from docket UE 94 was approved in Order No. 96-175, issued July 10, 1996.

**Q. Can you describe Staff's incremental adjustment to membership dues removed in this case?**

A. Of the membership dues the Company has initially included for 75 percent inclusion in rates in its direct filing, it appears Staff witness Rossow has removed instances of dues paid to organizations including, but not limited to, those with text "chamber of commerce", "development", or specific regional locations identified in its organization name, including many Oregon-based organizations.

**Q. Are the types of organizations for which membership dues are being proposed for further exclusion previously excluded from a 75 percent inclusion into rates?**

A. No. For example, none of the chambers of commerce suggested for removal from rate in Staff's testimony in this case were excluded in docket UE 399 or suggested for removal at any point in the UE 399 rebuttal or surrebuttal processes. The same is true in docket UE 374, the Company's prior GRC predating docket UE 399.

**Q. Do memberships and subscriptions to economic development and civic organizations benefit ratepayers?**

A. Yes. The Company's membership in these organizations strengthens relationships and provides a venue to communicate with customers and the community it services. More specifically, it allows the Company to strengthen relationships with key community and business leaders and build sustainable communities through enhanced

economic development, environmental and educational opportunities. The Company supports state and regional economic development agencies that work directly with expanding and relocating companies throughout its six-state service territory. In this manner, the Company indirectly assists prospective customers with their siting decisions; to the extent that customers locate in the Company's service territory, these decisions enhance electrical system asset utilization and reduces overall costs. Additionally, membership in these organizations is one of multiple communication channels the Company can use to communicate with customers and communities regarding important updates to utility service, rate changes, safety matters, etc.

**Q. Does the Company accept Staff's proposal to further adjust membership dues in this case?**

A. No. The Company asserts that its membership in the identified economic development and regional trade organizations is not maintained primarily to promote the Company but is in fact maintained to benefit and support customers as explained above.

***c. Routine Vegetation Management Expense***

**Q. Please explain your understanding of Staff witness Luz Mondragon's proposed adjustment to vegetation management expense.**

A. Staff witness Mondragon includes a $402,000 adjustment to decrease the level of vegetation management expense included in this rate filing to remove a total of $50 million instead of the $49.6 million being removed in the Company's Adjustment 4.11 – Vegetation and Wildfire Management O&M, where the Company removed Base Period net expense amounts to essentially "clear the slate" for Test Year

projected expenses to be added back. Staff argued that by the Company removing only $49.6 million, and not removing the $50 million of approved expenses from Base Period data, the difference is erroneously left in the case, and therefore incorrectly inflates Test Year expenses by the $402,000 that remained. Staff also claims the fact that because $50 million is the full approved amount of expenses to be collected in rates, that $50 million should be the amount removed from the case.

**Q. Are revenues collected under the Wildfire Mitigation and Vegetation Management (WMVM), and Wildfire Mitigation Plan (WMP) Automatic Adjustment Clause (AAC) reflected as part of base rates revenue requirement addressed in this case?**

A. No. WMVM revenues are collected through Schedule 94, and WMP AAC revenues are collected through Schedule 190. Neither are included in the calculation of base rates revenue requirement in this case.

**Q. Why is $49.6 million of vegetation management expense removed in Adjustment 4.11?**

A. In Adjustment 4.11, the Company is removing the amount of vegetation management and wildfire mitigation related expenses that were recorded in the Base Period of this case, which is the 12 months ended June 30, 2023. Adjustment 4.11 seeks to achieve two objectives:

1. Removes actual recorded wildfire mitigation expenses in the Base Period in its entirety. In this case, the Company is proposing to move all wildfire mitigation expenses incurred for Oregon's WMP to be recovered under the WMP AAC.

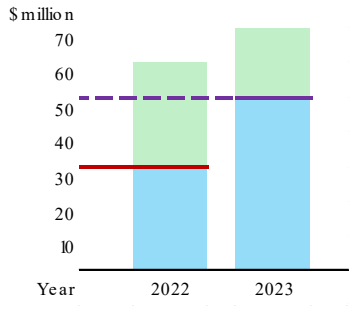
2. Removes actual recorded vegetation management expenses in the Base Period data in its entirety, to be replaced with the Test Year base rate amount of $67 million, as supported by Company witness Allen Berreth.

As the Company explained in the response to OPUC Data Request 488 for wildfire mitigation expenses, and which is also applicable to the treatment of vegetation management expenses in this case, "the Company removed the…expense that was actually recorded in the base period, not the amount that was approved in Docket UE-399" for both categories of expense. The response to OPUC Data Request 488 further explains that amounts "[e]mbedded in the Base Period is a net…expense amount (i.e. gross expense less deferral amounts recorded)."

**Q. Why is the Company not removing the $50 million approved amount from docket UE 399?**

A. The Company is not removing the $50 million approved amount from the Base Period results because it is not the amount of net vegetation management O&M reported in the Base Period, the 12 months ended June 30, 2023. To set the foundation to discuss this concept, the simple illustration below in Figure A demonstrates the recorded vegetation management expenses, the approved levels in each of the calendar years that the Base Period spanned across, and the portions that were deferred.

**Figure A—Historical Vegetation Management Expense**




In the simplified graphical illustration above, the red line represents the approved in-rates vegetation management expense threshold of $30 million in 2022. The purple line represents the increased $50 million in-rates threshold approved in 2023, as ordered in docket UE 399. The total bars for each year, 2022 and 2023 respectively, reflects the full (i.e. gross) amount of vegetation management O&M expenses incurred in each calendar year. In 2022, the Company incurred Oregon-allocated vegetation management expense totaling approximately $54.9 million,[17] of which a total of $24.9 million was deferred to a regulatory asset account. The $24.9 million was the portion of $54.9 million that was above the $30 million in-rates amount approved in docket UE 374. Similarly in 2023, total incurred Oregon-allocated vegetation management expense totaled approximately $66.3 million, of which approximately $16.3 million was deferred to a regulatory asset account. In each of the calendar years only a net amount, equal to the approved threshold amounts appropriately remained.

[17] 2022 WMVM filing.

**Q. If the Company appropriately left the approved level of vegetation O&M in rates, why is Staff's proposal to remove the $50 million as approved in docket UE 399 from this case inappropriate?**

A. Fundamentally, this case's revenue requirement is calculated using accounting data from the 12 months ended June 2023 as the starting point. This means the base year is made up of the last half of calendar year 2022 and the first half of 2023. As illustrated in Figure A above, these two calendar years have different approved in-base rates vegetation management O&M levels which would result in a total net vegetation management O&M expense that is not equal to $50 million. As well, the timing of when expenses are incurred and when deferral entries are made (and for which calendar year) could cause the amounts recorded in a certain period to not match the exact approved amount from docket UE 399. To reference back to the image in Figure A above, the total net vegetation management expense reflected in the 12 months ended June 2023 is some portion of the blue bar for 2022 on the left and some portion of the blue bar for 2023 on the right, and not necessarily the $30 million approved amount in 2022 nor the $50 million approved in 2023.

By removing $49.6 million of actual recorded net vegetation management O&M expenses extracted from the Company's accounting records, the Company is correctly and accurately clearing the slate of Base Period recorded vegetation management expenses, to be replaced by the Test Year forecasted amount of $67 million.

**Q. What is your recommendation on Staff's proposed adjustment to vegetation management expense?**

A. I recommend Staff's proposed adjustment to vegetation management expenses be rejected as the Company has removed all the actual expenses reported in the Base Period accounting data and has only included the proposed Test Year amount in this rate case filing. The additional adjustment proposed by Staff is not warranted or necessary.

***d. Wildfire Mitigation Expense***

**Q. Did Staff make a similar proposal on the WMP O&M component reflected in Adjustment 4.11?**

A. Yes. Staff witness Mondragon included a $5.3 million adjustment to decrease the level of wildfire mitigation expense included in the case so that a total of $19.7 million, instead of the $14.4 million, is removed through Adjustment 4.11.

**Q. Why is Staff recommending this adjustment?**

A. The reason Staff offered in support of this WMP O&M adjustment is largely the same as the reasoning supporting the vegetation management O&M adjustment discussed above. Staff mistakenly believes that in order to "clear the slate" in the Base Period of WMP expenses, the fully approved in-base rate amount of $19.7 million has to be removed.

In Adjustment 4.11, the Company is removing the amount of expense that was *actually recorded* in the Base Period of this case which is the 12 months ended June 30, 2023, similar to the explanation on vegetation management expenses, as discussed above. The Company removed the actual Base Period expense in this case

as wildfire mitigation expenses incurred in accordance with the Company's WMP will be recovered through the AAC.

**Q. Why is the Company not removing the $19.7 million approved amount?**

A. The Company has not removed the $19.7 million approved amount as that amount is not the amount that was recorded on the Company's books during the Base Period, the 12 months ended June 30, 2023.

**Q. What are some reasons why the actual recorded amount booked during the base year would not match the approved annual amount?**

A. For the same reasons explained in the discussion of Staff's vegetation management expenses above, the amount recorded in a 12-month period may not match the approved annual amount. One reason is this case includes a base year which is made up of the last half of calendar year 2022 and the first half of calendar year 2023. In 2022, there was no wildfire mitigation O&M approved in base rates.[18] The $19.7 million approved in base rates was approved through docket UE 399, with rates effective January 1, 2023. Finally, the timing of when expenses are incurred, and deferral entries are made (and for which calendar year) could cause the amounts recorded in a certain period to not match the exact approved amount.

**Q. Has the Company properly removed wildfire mitigation expenses from this rate case?**

A. Yes. The Company has removed all the wildfire mitigation O&M expenses from this case.

[18] Docket No. UE 374 approved $30 million in base rates for vegetation management and wildfire mitigation O&M, with no details on how the amount was to be allocated between the two categories. Therefore, the Company deemed the entire $30 million as applicable to vegetation management expense for ease of deferral and reporting in the WMVM and the WMP AAC.

**Q. What is your recommendation on Staff's proposed adjustment to wildfire mitigation expense?**

A. I recommend Staff's adjustment be rejected as the Company has removed all the actual expenses booked from the Base Year. The additional adjustment proposed by Staff is not warranted or needed, similar to the proposed vegetation management O&M adjustment discussed above.

**Q. Are there any other issues related to adjustments in Tab 4 you wish to address?**

A. Yes. There is a typographical labelling issue in the Company's proposed Adjustment 4.13 that needs to be clarified. Specifically, pages 4.13 and 4.13.1 of Exhibit PAC/1702, Cheung/122-123, and corresponding workpapers where the Company sought to quantify the change in O&M expense attributable to Jim Bridger Units 1 and 2 being converted into gas generation units, instances where figures were labelled as "Jim Bridger Units 1 & 2 O&M Expenses" should actually have read "Jim Bridger Plant O&M Expenses". Correspondingly, in my direct testimony, Exhibit PAC/1700, Cheung/23, on lines 4-6, the references to "Jim Bridger Units 1 and 2 O&M expense" should also have read "Jim Bridger Plant O&M expense". It appears this mislabeling caused Staff to misinterpret the analysis performed by the Company in how the decremental O&M adjustment for the conversion of Jim Bridger Units 1 and 2 was derived. Company witness Brad D. Richards provides further clarification on this issue in his reply testimony.

**Q. Do the dollars shown on pages 4.13 and 4.13.1 represent O&M for the entire Jim Bridger Plant?**

A. Yes, O&M data at a unit level is not readily available as explained in the Company's

response to OPUC data request 567. The objective of Adjustment 4.13 is to quantify the anticipated decremental change to O&M expenses at the Jim Bridger Plant due to the conversion of two units into gas generation units. Where unit level O&M data is not readily available, the Company resolved to use the 2025 O&M forecast for all of Jim Bridger Plant, compared against 12 months ended June 2023 (Base Period) actual O&M of Jim Bridger Plant to impute the decremental O&M impact of the gas conversion of Jim Bridger Units 1 and 2. The logic being that absent any conversion activity, activity levels at Jim Bridger units would presumably be fairly consistent year over year, and so where Units 1 and 2 being converted to gas units is the only major factor reasonably expected to drive changes to O&M levels at Jim Bridger, the comparison of forecasted test year O&M to base year O&M on a total Jim Bridger Plant basis is sufficient for the purpose of deriving the impact to O&M expenses due to the gas conversion of Units 1 and 2 of Jim Bridger Plant.

**Q. What is the impact to O&M expense with Jim Bridger Units 1 and 2 converting to gas in the Test Period?**

A. With the conversion of Jim Bridger Units 1 and 2, total plant O&M is expected to be reduced by approximately $10.9 million on total-Company basis and $2.9 million on an Oregon-allocated basis.

**Q. Given the clarification above, do you agree with Staff witness Mitchell Moore's adjustment regarding Jim Bridger Units 1 & 2 converted gas units O&M expense in the test period?**

A. No, Staff's adjustment is based on the assumption that the O&M expense presented in Adjustment 4.13 is just for Jim Bridger Units 1 and 2, rather than for the total Jim

Bridger Plant. Accordingly, Staff compared the $50.1 million total-Company Jim Bridger Plant O&M, against the average of O&M expenses for "gas-fired generation plant" provided in the Company's response to OPUC data request 567 and concluded that the $50.1 million Test Year Jim Bridger Plant O&M (which Staff understandably misunderstood as Jim Bridger Units 1 and 2 only) was too high. Based on the differential, Staff recommended a downward adjustment to O&M expenses to account for the gas conversion of Jim Bridger Units 1 and 2 to gas-fired units by approximately $9.0 million on an Oregon-allocated basis.

**Q. Is this comparison appropriate?**

A. No. As clarified above, the $50.1 million total-Company O&M expense figure is representative of Test Year expense for the entire Jim Bridger Plant, which includes Units 1 and 2 (converting to gas-fired generation), as well as Units 3 and 4, which will remain coal-fired units.

**Q. Aside from the misinterpretation of the $50.1 million test year O&M expenses as explained above, would it be appropriate to estimate plant O&M expense for Jim Bridger Units 1 and 2 based on an average calculation of other gas-fired facilities?**

A. No. Please refer to the reply testimony of Company witness Richards as to why an average calculation of other gas-fired facilities' O&M expense is not an appropriate forecast for the gas-converted Jim Bridger Units 1 and 2.

***e. Other O&M Expenses***

**Q. Is there any additional issues you wish to address in your reply testimony on O&M?**

A. No. Of note, various Staff witnesses expressed that Staff has reviewed a myriad of O&M topics in the Company's filing and proposed no adjustments in their opening testimony. These topics include Affiliated Charges, Gains on Property Sales, Generation Overhaul Expenses, Customer Accounts, Advertising & Marketing, Promotional Activities & Concessions, Customer Service and Informational Sales Expenses, Embedded Cost Differential, Directors Fees & Expenses, Director & Officer Insurance, and Administrative & General Expenses (except for specific items discussed above).

## C. TAB 5 – Net Power Costs

**Q. What revisions are included in Tab 5, Net Power Costs?**

A. The Company has updated net power costs to the level included in its TAM reply update filing on July 22, 2024, for purposes of showing the price changes related to both the TAM and GRC and for calculating the level of revenue sensitive items such as franchise taxes and bad debt expense.

Additionally, the Company revised one other adjustment in Tab 5, discussed in greater detail below.

***Adjustment 5.2, WRAP Fees and COSR Materials***

**Q. Have any parties raised an issue with this adjustment?**

A. No. In fact, Staff witness Chipanera testified that Staff did not have any concerns with the Western Resource Adequacy Program (WRAP) and Committee of State

Regulators (COSR) fees as proposed. However, as identified in the Company's response to OPUC Data Request 345, the WRAP and COSR fees adjustment as filed contained errors that ought to be corrected.

**Q. What changes did the Company incorporate in Adjustment 5.2 in its reply filing?**

A. The Company modified Adjustment 5.2 in its reply filing to reflect corrections identified in its response to OPUC Data Request 345. In the preparation of the response to OPUC Data Request 345, the Company observed an error in its calculation of the forecasted WRAP fees in Adjustment 5.2 as filed in my direct testimony. As reflected in Adjustment 5.2, specifically page 5.2.1, in Exhibit PAC/1702, Cheung/133, the forecasted WRAP fee reflected is approximately $1.1 million on a total-Company basis, calculated as a simple average of the Fiscal Year (FY) 2024-2025 and FY 2025-2026 base costs. However, upon re-examination, and as reflected in the Confidential Attachment to OPUC Data Request 345, the correct forecast WRAP fee should be $1.3 million on a total-Company basis. Correcting for this error results in an increase to Oregon-allocated expense of approximately $65,000.

## D. TAB 6 – Depreciation & Amortization

**Q. What adjustments or revisions is the Company making in Tab 6, Depreciation & Amortization Adjustments, for its reply filing?**

A. The Company has made no revisions or updates to the adjustments in Tab 6.

**Q. Has any party proposed changes or updates to depreciation expense and reserves in this case?**

A. Yes. Staff has proposed two adjustments to depreciation expense related to: (1) negative net salvage percentages for specific steam plants and (2) depreciation rates being used in this rate case filing for Jim Bridger Units 1 and 2, and Common Plant. I discuss and address each of Staff's proposals in more detail below. Staff also proposed an adjustment to depreciation reserves for changes made to depreciation expenses based on the two above mentioned items.

**Q. Does the Company agree with either of the adjustments being proposed to depreciation expense?**

A. No. The Company does not agree with either of the adjustments being proposed to depreciation expense.

**Q. If the adjustments being made to depreciation expense are not accepted, is the adjustment to depreciation reserve still needed?**

A. No. The adjustment being proposed to the depreciation reserve is only to reflect the depreciation reserve impact of the adjustments to depreciation expense. If the adjustments to depreciation expense are rejected, then the adjustment to depreciation reserves is no longer required.

***a. Negative Net Salvage Update***

**Q. Please describe Staff's proposal to update negative net salvage percentages for specific steam plant units.**

A. Staff proposes an adjustment to the net salvage percent of specific steam plant units that results in an estimated reduction to depreciation expense of approximately

$1.1 million. Per Staff witness Ming Peng's testimony, this proposal is intended to be focused on the steam plant units whose service lives have been extended.

**Q. Does the Company agree with Staff's proposal to adjust negative net salvage percentages for specific steam plant units?**

A. No. First of all, witness Peng's testimony states that proposals to adjust negative net salvage percentages were focused on steam plant units for which depreciable lives have been extended in this case. However, the Company clarifies that it is not proposing any depreciable life updates in this case and notes that no changes have been made to the lives of the steam units included in Staff's analysis since they were approved in docket UE 374 (for Dave Johnston Unit 1, Dave Johnston Unit 2, Dave Johnston Unit 4, Naughton Unit 2, and Naughton Unit 3) and docket UE 399 (for Colstrip).

Negative net salvage is a component of a depreciation rate that is re-assessed as a part of every depreciation study. It determines what needs to be accrued through the depreciation rate in excess of an asset's remaining net book value for any removal cost net of salvage. It considers not only the cost of removal, net of salvage, for final decommissioning of a facility, but also the interim cost of removal, net of salvage, over its remaining operational life. The calculation of this interim amount is highly complex and involves a combination of actuarial analysis of the Company's historical data, the application of updated Iowa Curves to project future interim removal spends, and informed judgement based on the interpretation of statistical and utility industry trends. This process requires the services of a depreciation consultant that the Company would have to hire to accurately quantify any adjustments made to existing

negative net salvage percentages. It would not be appropriate to attempt an approximated update to these parameters in this proceeding, but rather wait until its next depreciation study to revisit and recalibrate negative net salvage percentages.

Additionally, a statement in witness Peng's testimony asserting that, "[g]enerally speaking, as the depreciable life of an asset is extended, the net salvage rates tend to be lower," is fundamentally incorrect. Extending the depreciable life of a steam unit introduces the potential of experiencing additional capital replacements and an increase in projected interim retirements. An increase in projected interim retirements would lead to an increase in projected interim removal spend. Increased projected interim removal spend results in needing higher negative net salvage rates, not lower, to ensure recovery of any increased projected interim removal spend through depreciation over the remaining life of the steam plant unit.

**Q. Has Staff previously made similar proposals to adjust negative net salvage percentages in the past?**

A. Yes. Staff witness Peng made the same exact proposal, with the identical proposed reduction to net salvage percentages for the same steam plants, in the Company's most recently concluded GRC, docket UE 399. Staff's proposal to adjust negative net salvage in that case ultimately did not get adopted in the settled outcome approved by Order No. 22-491.

***b. Adjustment to Jim Bridger Depreciation Rates***

**Q. Please describe the adjustment being proposed to the depreciation rates used in this filing for Jim Bridger Units 1 and 2, and Common Plant.**

A. Staff witness Peng recommends an adjustment related to the depreciation rates for

Jim Bridger Units 1 and 2, and Common Plant. Staff's recommendation is made with the intention to reflect updated depreciation rates for those units due to "extending the service life for Jim Bridger Units 1 and 2, and Common Plant from 2023, 2025, and 2025, respectively, to 2029".[19] Based on Staff witness Peng's review of Excel workpapers supporting the Company's response to OPUC Data Request 156, Staff witness Peng has concluded that the depreciation is not properly reflecting the assumption of the extended 2029 end of depreciable life for Jim Bridger Units 1 and 2 and Common Plant, and that the 7.05 percent depreciation rate as approved in docket UE 374 is the basis on which the Company has based the calculation of the composite depreciation rates applied to Jim Bridger Units 1, 2 and Common Plant assets in this case. Accordingly, Staff witness Peng's recommendation is to revise the depreciation rate calculation applied to these assets from being based on 7.05 percent (approved in docket UE 374) to 6.34 percent (to reflect the extended end of depreciable life of 2029).

**Q. Is Staff's conclusion correct?**

A. No. It appears Staff witness Peng may be misreading the data presented in OPUC Data Request 156.

**Q. On page 12 of Exhibit Staff/1500, Staff witness Peng states that, "PacifiCorp is proposing plant retirement dates for Units 1 and 2 and the Bridger Common account of 2029." Is this a correct statement?**

A. No. The Company has not proposed changes to the retirement date for Jim Bridger Units 1 and 2, and Common Plant in this filing. The Company has instead reflected

[19] Staff/1500, Peng/10.

depreciation rates with the assumed end-of-service life at 2029, based on the settlement outcome approved in the Company's most recently concluded GRC, docket UE 399. In the second partial stipulation from docket UE 399, parties agreed to updating Jim Bridger Units 1 and 2, and the Common Plant to assume a depreciable life of the end of 2029. This settlement stipulation was approved, and the updated depreciable life and corresponding depreciation rate was implemented.

**Q. In this rate case filing did the Company use depreciation rates for Jim Bridger Units 1 and 2 and Common Plant that reflect an end of service life of 2029?**

A. Yes. The Company has included in this rate case filing depreciation rates that assumes an end of service life of 2029, as approved in docket UE 399. Also, as clarified above in the discussion of Staff's proposed adjustment to negative net salvage percentages, the Company has not proposed any further changes to depreciable lives of steam plants in this proceeding.

**Q. Since the Company is already using depreciation rates that reflect a depreciable life through 2029 for Jim Bridger Units 1 and 2 and Common Plant, is Staff's proposed adjustment to the depreciation rates for Jim Bridger Units 1 and 2, and Common Plant necessary?**

A. No. The adjustment being proposed by Staff witness Peng is not needed in this rate case filing as the Company has already incorporated the updated depreciation rates (i.e. assuming end of depreciable life at 2029) for Jim Bridger Units 1 and 2, and Common Plant into the calculation of composite depreciation rates being used in this rate case filing. Accepting Staff's incremental adjustment would be duplicating the impact of the change in depreciation rates for this plant.

**Q. Where can the composite depreciation rate used for steam plant with a system generation (SG) allocation factor (Jim Bridger Units 1 and 2 and Common Plant inclusive) be verified in the Company's filing?**

A. The composite depreciation rate in this filing used for steam plant which is allocated using the SG allocation factor is 6.33 percent, which is slightly lower than the 6.34 percent rate being proposed by Staff witness Peng. This composite depreciation rate can be found in Exhibit PAC/1702, on page 6.1.4 through page 6.1.13. The formula and inputs underlying the development of the steam plant composite depreciation was also provided in the attachment provided with the Company's response to OPUC Data Request 156, specifically on the tab called "Composite Rates OREGON".

**Q. Is the attachment to OPUC Data Request 156 referenced above the same attachment that is referenced in Staff witness Peng's testimony on which Staff's conclusion is based?**

A. Yes, the Company believes this is the same attachment.

**Q. Please provide a more elaborate description of the attachment to OPUC Data Request 156.**

A. The Excel attachment accompanying the Company's response to OPUC Data Request 156 is a robust work file that includes many tabs to show how depreciation rates from the approved depreciation study are used to calculate composite depreciation rates (by function and factor) used in this filing. The attachment also demonstrates how the composite rates are applied to plant in service amounts to arrive at the calculated depreciation expense and depreciation reserve amounts included in the Test Period.

This attachment contains intact, functional, links and helpful comments to help reviewers navigate through the many tabs of information.

**Q. Where in this attachment does it present the approved depreciation rates that are being used to derive the composite depreciation rates used for Jim Bridger Unit 1 and Unit 2, and Common Plant?**

A. The depreciation rates can be found on the tab called "Oregon Coal", specifically starting on row 214. The approved depreciation rates are then pulled into the tab called "JAM Extract Method Data Jun23" and are then rolled up into composite depreciation rates on the tab called "Composite Rates OREGON". Those composite depreciation rates, calculated by function and factor, are then applied to plant in-service amounts reported under each respective function and factor combination. In Excel cell G63 on the "Composite Rates OREGON" tab, the composite depreciation rate for steam plant, allocated on an SG factor (i.e. Jim Bridger Units 1 and 2, and Common Plant assets inclusive), is calculated as 6.33 percent.

**Q. Why do you think Staff arrived at the erroneous conclusion that the depreciation rate being applied to Jim Bridger Units 1 and 2 and Common Plant in this case is 7.05 percent?**

A. I cannot be certain, but I suspect Staff examined the "Oregon Coal" tab in the attachment referenced above, and assumed that the accrual rate of 7.05 percent on Excel row 314, Column U, which is the depreciation rate originally approved in docket UE 374 total depreciable steam production plant, is the figure that is pulled through into the calculation of the relevant composite depreciation rates used in this case. However, the 7.05 percent figure is only provided as part of the original

document supporting depreciation rates adopted in docket UE 374 so that an unaltered original document can be presented as part of the response to OPUC Data Request 156. In actuality, the effective depreciation rates that are relied upon to calculate the composite depreciation rate used in this case are being sourced from Excel Column AA, between rows 219 and 258, resulting in a composite depreciation rate used in this filing of 6.33 percent.

**Q. Does the Company have any other concerns with how this proposed adjustment is calculated?**

A. Yes. The dollar amount of the depreciation expense adjustment being proposed for Jim Bridger Units 1 and 2, and Common Plant proposed by Staff was calculated using electric plant in-service amounts as of the year 2020, from the depreciation study docket UM 1968 instead of, the electric plant in-service balances used in this rate filing. An adjustment being proposed to depreciation expense in the rate case should be based off electric plant in-service balances included in this rate case filing.

**Q. Were there other inaccuracies in Staff's testimony in the discussion of depreciation expenses that you wish to clarify?**

A. On page 12, lines 12-17, Staff witness Peng testified that, "…the original retirement date for depreciation purposes for the Cholla unit 4 coal plant was December 2020 in docket UE 374, which was then extended to April 2025 in docket UM 1968. After that, Cholla unit 4 was not included in docket UE 399, the general rate case depreciation schedule, but it was added back to the depreciation schedule in docket UE 433 with the retirement date of April 2025 approved in docket UM 1968." The Company clarifies that it did not extend the service life from December 2020 to April

2025 as described by Staff. Docket UE 374, the Company's 2021 GRC, was filed after docket UM 1968, which was the Company's 2018 depreciation study. In the 2018 depreciation study, Cholla Unit 4 was included with an assumed end of depreciable life of April 2025. Cholla Unit 4 was retired at the end of 2020, and so subsequently, in the Company's 2021 GRC, the Company revised the expected end of depreciable life for Cholla Unit 4 to December 2020, consistent with its retirement date. In neither docket UE 399, nor this current proceeding, did the Company include any depreciation expense for Cholla Unit 4 in the test period of each case.

***c. Hydro Licensing Fees***

**Q. What is the next issue raised Staff witness Peng?**

A. Staff also recommended an adjustment related to depreciation associated with hydroelectric construction projects based on a misunderstanding that hydro licensing fees are recorded as intangible plant *and* used to fund construction.

**Q. How does the Company respond to Staff's concern that hydro licensing fees fund construction projects, thus resulting in double recovery of these costs?**

A. Staff's concern is invalid, for reasons I will discuss below.

**Q. Please explain why Staff's basis for the recommended depreciation adjustment associated with hydroelectric projects is flawed.**

A. Staff Witness Peng's statements regarding the accounting for, use-of, and basis for recovery of hydro license fees is incorrect. Hydro license fees paid to the FERC are not recorded as intangible plant, are not used to fund the Company's construction projects and are not recovered via amortization expense included in base rates. Rather, hydro license fees are paid to the FERC annually over the term of the license,

charged to operating expense as incurred and recovered as operating expense with no license costs included in intangible plant, rate base or amortization expense. Therefore, there is no possibility of double recovery of the license fees or hydro construction projects.

**Q. Please describe the types of costs associated with FERC licensed hydroelectric projects and the basis of accounting and recovery of costs for such projects.**

A. There are three general categories of costs associated with FERC licensed hydroelectric projects that are conflated in Staff's testimony.

First, as described above, there are annual license fees paid to the FERC. These fees are determined by the FERC and vary from year to year over the term of a long-term license. These license fees are periodic expenses, not capital assets, and thus are charged to operating expenses as incurred. These operating expenses are recovered through inclusion in the applicable test period expenses used to calculate revenue requirement in a GRC. These fees are not recorded as intangible plant nor used to construct capital projects as indicated by Staff witness Peng. They are paid to the FERC and the FERC does not remit any funds back to the Company. Therefore, there is no possibility that such license fees are used to fund project construction.

Second, in the process of obtaining a long-term hydroelectric license from the FERC (with terms that range from 30 to 50 years), the Company incurs costs such as internal labor, environmental studies and outside legal fees that are recorded to construction-work-in-progress during the period of licensing efforts. Once a long-term license is issued by the FERC and accepted by the Company, these costs are

placed into service as intangible plant. These costs are recovered through amortization expense and the intangible plant is also then included in rate base.

Third, as part of the licensing process, negotiations with stakeholders such as Native American tribes, resource agencies, conservation groups, etc., result in proposed mitigation measures, typically memorialized in a settlement agreement, which are largely incorporated into a FERC hydroelectric license. These settlement agreements typically create multiple obligations for the Company over the term of the license, none of which are funded by FERC license fees. These obligations vary and may include items that are capital in nature (e.g., constructing a fish ladder on Company-owned property or constructing a structure off Company property) or that are expense in nature (e.g., maintaining grounds in the vicinity of the hydroelectric project). Capital items on Company property and operating expense items are accounted for and recovered based on their nature, either as plant, via depreciation or amortization expense and inclusion in rate base, or as operating expense. Capital items off Company property are capitalized to intangible plant and recorded as a liability upon acceptance of the license and settlement agreement. These off-property capital investments are not treated as intangible plant for ratemaking purposes since the cash outlay occurs in future periods. Thus, rather than recovering based on amortization expense and including the intangible plant in rate base, these off-property capital costs are recovered based on cash outlay. Again, none of these costs are funded by license fees paid to the FERC, and there is no possibility of double recovery of any of these costs.

**Q. Please summarize your recommendation regarding Staff's recommended adjustment to remove depreciation associated with projects funded by hydro license fees.**

A. Staff's adjustment is unnecessary because no component of hydro license fees is used to fund construction projects.

***d. Staff's Concern Regarding Allowance for Funds Used During Construction (AFUDC)***

**Q. What is the final issue challenged by Staff witness Peng?**

A. Staff witness Peng proposed an unquantified change to the treatment of AFUDC that is confusing and inappropriate.

**Q. What concerns does Staff have with regards to the Company's AFUDC.**

A. While Staff concluded that "The Company's AFUDC calculations meet FERC calculation procedures and meet Oregon regulatory requirements…,"[20] Staff witness Peng also state that "FERC has indicated that if the FERC AFUDC rate is different than the state-approved rate, the AFUDC capitalized should be split between utility plant and a regulatory asset. The amount included in the regulatory asset is the difference between the State AFUDC rate and the FERC AFUDC rate."[21]

**Q. Did Staff offer an adjustment to revenue requirement for this proposal?**

A. No, it does not appear Staff witness Peng included an adjustment quantifying the impact of the AFUDC proposal described above.

[20] Staff/1500, Peng/29.
[21] Staff/1500, Peng/26.

**Q. How did Staff arrive at the conclusion that there were "excess" AFUDC amounts that should be deferred to a regulatory asset?**

A. In reviewing the Company's response to OPUC Data Request 159, where the AFUDC rate calculation was provided for multiple historical years, Staff observed that the Total AFUDC Rate (composed of a debt component, and an equity component) was calculated to be higher than the authorized weighted average cost of capital (WACC) for calendar years 2022, 2023 and 2024. For this reason, Staff is recommending that the total portion of AFUDC costs that exceeds the authorized rate of return be recorded as a regulatory *liability* on the utility's balance sheet, consistent with the FERC guidance referenced on page 23 of witness Peng's testimony.[22]

**Q. Is the Company aware of a requirement that its AFUDC rate is essentially capped at its state-approved WACC?**

A. No.

**Q. What basis does witness Peng cite in support of this "requirement"?**

A. Since the Company was not aware of any such guidance from FERC, capping its AFUDC rate at state-approved WACC, the Company issued a data request to Staff asking for the source of supporting documentation for the statement made in Staff/1500, Peng/26, lines 13-15, regarding the treatment of AFUDC capitalized if its FERC calculated AFUDC rate was different than the state-approved rate. A copy of the response provided by Staff is included as Exhibit PAC/3303. Accompanying Staff's response was two attachments:

[22] Staff/1500, Peng/28. However the Company believes the Staff's reference to a regulatory liability should actually be a reference to a regulatory asset, in the context of the balances being discussed. This can also be confirmed as the referenced "excess" AFUDC in Avista's audit was directed to be recorded to FERC Account 182.3, which is a regulatory asset account.

- Exhibit 1, the Audit Report published in the "Audit of Avista Corporation's Compliance with its Open Access Transmission Tariff; the Open Access Same-Time Information System regulations; the accounting requirements of the Uniform System of Accounts Prescribed for Public Utilities and Licensees; and the reporting requirements of the FERC Form No. 1 Annual Report" (Exhibit 1), FERC Docket No. PA18-2-000, and
- A subsequent "2019 Report on Enforcement" (Enforcement Report) published in FERC Docket No. AD07-13-013 where the outcome of the Avista audit was summarized.

More specifically, Staff cites to an excerpt in Exhibit 1 on pages 2 and 3, summarizing a noncompliance item determined in Avista's audit, saying "Avista accounted for the excess arising from higher state-approved AFUDC over AFUDC as computed in accordance with the Commission's accounting regulations as a cost of plant in Account 101, Electric Plant in Service, through Account 107, Construction Work In Progress, instead of recording the excess in Account 182.3, Other Regulatory Assets." Further, Staff also points to page 63 of the Enforcement Report, that reads "…accounting for excess AFUDC accrual arising from higher state-approved versus Commission-approved AFUDC rates as a cost of plant rather than a regulatory asset in Account 182.3."

**Q. Do you agree that these referenced documents support Staff's proposed adjustment to AFUDC for PacifiCorp?**

A. No. A few points ought to first be clarified. In Staff's testimony, where Staff witness Peng states excess AFUDC should be recorded to a regulatory liability, in all

instances under the context of this discussion, the correct account referenced should be a regulatory asset. Where both documents cited by witness Peng addresses the excess AFUDC issue, amounts deemed "in excess" are instructed to be recorded to FERC Account 182.3, Other Regulatory Assets.

Next, the referenced audit was done in examination of FERC Open Access Transmission Tariff (OATT) rates, and not in a state utility-level retail ratemaking context. Accordingly, it should be noted that as defined in the Overview section of the Executive Summary in the Exhibit 1 attachment, the reference to "Commission" (with a capitalized C) is a reference to the FERC, and not any state-regulatory utility commission.[23]

**Q. Please continue explaining why the audit reports supplemented by Staff should not apply to PacifiCorp.**

A. In Exhibit 1, FERC found "Avista's methods for calculating and accounting for its AFUDC rate to be deficient, and caused Avista's AFUDC to exceed the maximum AFUDC permitted…by Commission's regulations."[24] As explained above, "Commission" in this context is a reference to the FERC. At the bottom of the same page discussing the deficient findings in Avista's AFUDC, the report goes on to explain that Avista inappropriately included several components in its AFUDC calculation that caused this "excess" AFUDC to result. These items include the inclusion of revolving credit facility commitment fees without FERC approval in the calculation of its AFUDC rate, incorrect inclusion of specific FERC account balances as part of its equity and debt component computation, as well as using the monthly

[23] PAC/3303, Cheung/7.
[24] PAC/3303, Cheung/31.

equity and long-term debt balances in its AFUDC rate, instead of the balances existing at the end of the prior year, as required by FERC. Of more relevance here, there is a thorough discussion of the issue FERC found with regards to Avista's AFUDC in comparison to AFUDC rates approved by state regulators.[25] The report states:

> Avista computed its AFUDC rate for purposes of its Commission-jurisdictional transmission rates following the states' guidelines, rather than the [FERC] Commission's regulations, which resulted in AFUDC rate that exceeded the maximum AFUDC rate computed in accordance with the [FERC] Commission's accounting regulations due to the significantly lower cost of Avista's short-term borrowings compared to its long-term financing. Avista did not provide any evidence of [FERC] Commission approval for using AFUDC rate that exceeded the maximum AFUDC rate permitted under the [FERC] Commission's accounting regulations[.][26]

As a result of the deficiencies identified in the audit, FERC found the AFUDC calculated by Avista to exceed the maximum AFUDC permitted by the Commission's regulations. Again, "Commission" as defined in this document is the FERC. In other words the "excess" AFUDC referenced is "excess" relative to FERC approved levels of AFUDC. Based on the findings in the report, it is clear that the appropriate AFUDC levels are ones established in compliance with the FERC approved AFUDC rate, and not any state regulator established AFUDC rate, unless explicit approval from FERC has been obtained.

**Q. Does PacifiCorp have a state regulator approved AFUDC rate?**

A. No.

[25] PAC/3303. Cheung/30.
[26] PAC/3303, Cheung/31.

**Q. Has PacifiCorp's AFUDC calculations been audited or reviewed by the FERC?**

A. Yes, the Company's AFUDC calculation methodology was reviewed by the FERC in 2017 as part of an audit of the Company's compliance with its wholesale formula rate, the accounting requirements of the Uniform System of Accounts Prescribed for Public Utilities and Licensees, and the reporting requirements of the FERC Form No. 1, Annual Report (Docket No. FA16-4-000). A copy of this audit report is included as Exhibit PAC/3303. While several minor deficiencies were identified, there was no corresponding directive from FERC for any deferral of AFUDC amounts as regulatory asset balances. Subsequent to the report, updates rectifying issues identified in FERC's findings were made and the Company's AFUDC process has not changed since that time.

**Q. Has the Company changed its AFUDC calculation methodology in this case?**

A. No. In fact, the Company has consistently applied the same methodology since the 2017 FERC audit report was published, during which time three GRCs have been filed in Oregon, and AFUDC costs have been included in rates calculated using the methodology described above. AFUDC recorded in 2022 for assets placed in-service through 2022 is currently being recovered in rates as part of Electric Plant In-Service rate base with the approval of general rates effective January 1, 2023, in docket UE 399.

**Q. Can you provide an overview of the Company's methodology in calculating AFUDC?**

A. PacifiCorp calculates its FERC AFUDC rate in accordance with the Uniform System of Accounts within Code of Federal Regulations (CFR) 18, Part 101, Electric Plant

Instructions 3.A (17), which includes the FERC mandated formula for calculating both the debt and equity component rates that make up the AFUDC rate. The Company calculates the FERC-mandated AFUDC rate at the beginning of the year and then, based on actual activity throughout the year, updates it each month and applies a rate in its accounting system that will keep the total amount of AFUDC applied during the year at or below the calculated, FERC-mandated amount for the year based on the FERC-mandated AFUDC rate. This process complies with FERC Order 561 based on the results of the Company's 2017 audit by the FERC.

**Q. Can you explain why the total AFUDC rate in the calendar years referenced turned out to be higher than the authorized WACC?**

A. Yes. While the authorized WACC represents the Company's WACC at a point in time during rate case proceedings, the AFUDC rate calculated in compliance with FERC guidance is updated more often than GRCs are filed. The AFUDC rate calculated under FERC guidance is also likely to be different than the Oregon authorized WACC as it is calculated for the entire organization, not just Oregon. The cost of equity component in the FERC AFUDC rate is the weighted average of the authorized ROE for each jurisdiction the Company operates in, which could be lower or higher than the Oregon authorized WACC. The debt component rate also fluctuates over time, with increasing interest rates pushing the costs of both short and long-term borrowing higher over the last few years. While the balances and costs of long-term debt used in the AFUDC rate calculation are fixed for each year in question, short-term debt balances are updated with actual activity and interest rates each month as part of determining the rate that needs to be entered into the

accounting system in order to keep the amount of AFUDC recorded at or below the FERC-mandated rate for each year in question.

**Q. Does the Company agree with Staff's recommendation that AFUDC that exceeds the authorized rate of return is to be recorded to a regulatory asset on the utility's balance sheet?**

A. No. Staff's recommendation is based on citation to a FERC audit report that is not applicable to PacifiCorp. There is no "excess" AFUDC in PacifiCorp's case warranting deferral to a regulatory asset as the Company is currently calculating AFUDC in accordance with FERC-mandated methodologies. The Company's AFUDC rate calculations have been consistently applied and upheld in Oregon rates through approval of general rates from GRCs in the past decade. Finally, the Company's inputs and methodology in calculating AFUDC properly reflects the financing costs of funds used in the construction of capital projects.

## E. TAB 7 – Tax

**Q. Did the Company make any revisions in Tab 7, Tax Adjustments, for its reply filing?**

A. Yes. The Company made revisions or updates to the following adjustments contained in Tab 7, each discussed in more detail below in my testimony.

- Adjustment 7.3, Production Tax Credit (PTC)
- Adjustment 7.4, Power Tax Accumulated Deferred Income Tax (ADIT) Balance
- Adjustment 7.6, Wyoming Wind Generation Tax

Additionally, as part of the revenue requirement calculation, PacifiCorp's model automatically recalibrates interest expense on a pro forma basis with each

change to pro forma rate base. Therefore, as a result of the rate base revisions and updates included in this reply filing, Adjustment 7.1, Interest True-Up, has also been recalculated to reflect the appropriate level for the Test Period.

***Adjustment 7.3, Production Tax Credit***

**Q. Please discuss the revisions to Adjustment 7.3, Production Tax Credit.**

A. Consistent with the update to NPC forecast modelled in the TAM settlement, the underlying generation data assumed in the Test Period had also been updated. Correspondingly, PTC calculations had to be updated to synchronize generation assumptions in this GRC and the concurrent 2025 TAM filing.

***Adjustment 7.4, Power Tax ADIT Balance***

**Q. Please describe the correction made to Adjustment 7.4.**

A. It was discovered after the case was filed that the Base Period amount used in calculating the adjustment for situs allocated Depreciation Flowthrough was incorrect. As a result, the situs allocated Depreciation Flowthrough was overstated by approximately $258,000 in the direct filing. Correcting for this error resulted in an increase to revenue requirement of approximately $355,000.

***Adjustment 7.6, Wyoming Wind Generation Tax***

**Q. What update has been made to Adjustment 7.6, Wyoming Wind Generation Tax?**

A. This adjustment has been updated to include the updated generation information, consistent with the latest forecast used in the TAM Reply Update filed on July 22, 2024.

## E. TAB 8 – Rate Base

**Q. What adjustments or revisions is the Company making in Tab 8, Rate Base Adjustments, for its reply filing?**

A. The Company has made revisions or updates to the following adjustments, discussed in more detail below in my testimony.

- Adjustment 8.1, Cash Working Capital
- Adjustment 8.6, Regulatory Assets and Liabilities Amortization
- Adjustment 8.11, Emissions Control Investment Adjustment
- Adjustment 8.14, Miscellaneous Rate Base
- Adjustment 8.18, Wildfire Restoration Costs Deferral Amortization

***Adjustment 8.1, Cash Working Capital***

**Q. Please address the updates to Adjustment 8.1, Cash Working Capital made in this reply filing.**

A. Similar to Adjustment 7.1, Interest True-Up, Adjustment 8.1, Cash Working Capital, also automatically recalibrates as part of the revenue requirement calculation in the Company's model. Additionally, the Company updated the net lag days (the time between when the Company provides goods and services to when payment is received) from 10.92 days as filed in its direct filing to 11.07 days as identified in the Company's response to OPUC Data Request 249, where typographical errors were identified in transactions reflected in the 2022 Lead Lag study work papers with invoice dates of "12/13/2002", when it should have read "12/13/2022".

**Q. Did any party propose changes to the Company's net lag day calculation?**

A. Yes. Staff claims that Oregon's net lag day in the 2022 Lead Lag study is too high. In

particular, it is higher than any other jurisdiction that the Company operates in. Accordingly, Staff is proposing to eliminate the calculated "billing lag" (a component in calculating the revenue lag days within the lead lag study), in the Company's 2022 Lead Lag study, by setting it to zero.[27]

**Q. What is the Company's calculated billing lag in the 2022 Lead Lag study that is used in this proceeding?**

A. The "billing lag" is calculated to be 3.32 days. The "billing lag" is the period beginning when the meter is read and when the invoice is processed.

**Q. Why is Oregon's total net lag days higher than the other jurisdiction?**

A. The biggest driver in Oregon's total net lag days is actually high "collection lag" identified in tab "3.3" of the 2022 Lead Lag Study. The "collection lag" is the time interval from the invoice date until the customer pays for the service. Oregon's collection lag is 30.56 days. The Company does not have any control over when customers pay their bills and can only make it "easier" for customers to pay as stated in the Company's response to OPUC Data Request 581.

**Q. Staff witness Chipanera states in Exhibit 200 that other Oregon utilities bill their customers on the same day that meters are read. What is the Company's response to this?**

A. It is highly unlikely that a utility can immediately bill a customer as an invoice is not generated simultaneously to the meter being read so there is inherently a "billing lag". Also, each utility's processes are unique, so other utilities' processes have no bearing on the processes used at the Company. Each utility has unique technology and

[27] Staff/200, Chipanera/12-13.

proprietary processes that will be fundamentally different, resulting in different lag time.

**Q. Does the Company agree with Staff's recommendation to reduce the "billing lag" to zero?**

A. No, the Company does not agree to the complete elimination of "billing lag" from the Company's 2022 Lead Lag study, by setting it to zero. There is necessary processing time between when a meter is read to the issuance of an invoice and that timeframe needs to be accounted for. The "billing lag" is not the driver in the total net lag days in Oregon. The driver is how long it takes Oregon customers to pay their invoices, which the Company has little to no control over.

***Adjustment 8.6, Regulatory Assets & Labilities Amortization***

**Q. Please address the updates to Adjustment 8.6, Regulatory Assets & Liabilities Amortization made in this reply filing.**

A. As identified in the Company's response to OPUC Data Request 494, the Company discovered that the deferral balance of distribution system planning (DSP) expenses included in the Company's request for amortization reflected a minor clerical error that resulted in the accrued balance through calendar year 2023 to be overstated by approximately $61,000. Correcting for this error resulted in a decrease in revenue requirement of approximately $27,000.

**Q. Do you address Staff witness Dlouhy's arguments against the prudency of the DSP cost deferral?**

A. No. Please refer to the reply testimony of Company witness Matthew D. McVee where this is addressed.

*Adjustment 8.11, Emissions Control Investment Adjustment*

**Q. How has Adjustment 8.11 been updated in the Company's reply filing.**

A. Adjustment 8.11 reflects in results rate base and return disallowances on emissions control investments as ordered in Order No. 20-473 in docket UE 374. Because the Company has revised its requested rate of return in reply, the corresponding calculation to remove the return disallowance from revenue requirement needed to be recalibrated to reflect the updated ROE and cost of debt requested in reply.

*Adjustment 8.14, Miscellaneous Rate Base*

**Q. What changes were identified in Adjustment 8.14 since this GRC was filed?**

A. Five corrections were identified as necessary through the discovery process as discussed in the opening testimony of Staff witness Julie Dyck. Staff summarized each correction and recommended that revenue requirement in this case be reduced by $672,000 as a result of making these corrections in reply.

**Q. Does the Company accept the corrections summarized by Staff?**

A. Yes. The Company had acknowledged in discovery that it would correct the inconsistencies identified in the Company's response to OPUC Data Requests 200, 518 and 536.

**Q. Did Staff challenge any other aspects of fuel stock balances in this case?**

A. Yes. Staff witness Dyck questioned the amount of fuel stock held at Jim Bridger plant. Company witness James C. Owen presents the Company's response to Staff's concern. Additionally, in the evaluation of the accuracy of fuel stock balances assumed in the Test Year forecast at Jim Bridger, the Company identified an additional revision that was necessary to the projected fuel stock balance at the

Hunter plant. Accordingly, the Company reflected this revision to its forecasted fuel stock in the Test Year in its reply filing.

**Q. What is the aggregate revenue requirement impact of the corrections and updates made to Adjustment 8.14 for fuel stock changes?**

A. The net impact of the corrections, and the revision to projected fuel stock balances at Jim Bridger and Hunter resulted in a net increase to the revenue requirement in this case of approximately $68,000.

**Q. Were other adjustments proposed to miscellaneous rate base balances in this case?**

A. Yes. Staff witness Moore recommended the use of a three-year average of "average of monthly average" balances from 2021 to 2023, escalated by an inflation index of 0.31 percent to establish materials and supplies (FERC Account 154) balances in this case. Staff states that this proposed adjustment results in a reduction to rate base of approximately $21.9 million on an Oregon-allocated basis, taking the Test Period balance from $129,822,071[28] to $107,826,222.

**Q. Do you have concerns about Staff's proposed calculation of the reduction to materials and supplies?**

A. Yes. First, in the Company's direct filing, Exhibit PAC/1702, Cheung/39, on line 2092, the Oregon-allocated materials and supplies balance is $128,895,465, slightly different from the balance referenced in the opening testimony of Staff witness Moore.

[28] Staff/1200, Moore/3, line 6.

Second, Staff stated that "PacifiCorp's inflation index of 0.31 percent" was used to escalate the historical multi-year "average of monthly average" balance. The Company had not provided anywhere in its filing inflationary indices that would be appropriate to apply to rate base balances. In the Company's proposed Adjustment 4.10, O&M Escalation, IHS Markit indices for escalation were provided, but these indices are prepared at the FERC functional subcategory level and are denoted with their corresponding FERC account number. These indices are applicable exclusively to the escalation of amounts recorded in O&M FERC accounts. Accordingly, the Company is uncertain as to where the proposed 0.31 percent escalator is sourced from.

Finally, Staff explained that an allocation factor "0.331889"[29] was applied to the system-level escalated multi-year "average of monthly average" FERC Account 154 balance to arrive at the revised Oregon-allocated Test Year balance of $107,826,222. The Company cannot confirm the source of the referenced "0.331889" allocation factor. As shown in Exhibit PAC/1702, FERC Account 154 balance consists of different components that reflect a variety of allocation percentages assigned in accordance with the 2020 Protocol, including situs-assignment SG, system overhead (SO), and system net plant-distribution (SNPD) factors. To properly calculate Oregon's share of system material and supplies balances, each component needs to be properly isolated, so that the correct 2020 Protocol allocation factor can be applied accordingly.

[29] Staff/1200, Moore/4.

**Q. What is Staff's argument in support of this rate base methodology change?**

A. Staff expressed that Commission policy typically authorizes utilities to include an allowance for non-fuel materials and supplies in rate base, and that Staff generally uses a "3-year historical average of monthly balances" to forecast material and supplies inventory.[30]

**Q. Is Staff's characterization accurate?**

A. No. For over a decade, the Company has included non-plant rate base balances in rate proceedings on a 13-month simple average basis in the Test Year. A "3-year historical average of monthly balances" to forecast material and supplies inventory had not been proposed in at least the Company's most recent two GRCs, dockets UE 374 and UE 399.

**Q. Would it be appropriate to use a "3-year historical average of monthly balances" to establish Test Year rate base balances?**

A. No. To the best of my knowledge, I am not aware of instances where rate base balances are established in rates as a historical average. This is because historical rate base is not a representative measure of the anticipated future level of rate base that will be in-service and serving customers. Also, materials and supplies are procured in accordance with the anticipated needs in the upcoming operational periods, and would also fluctuate with procurement costs, as prices of materials and supplies change over time due to supplies and demand, or inflationary pressures. For these reasons, reverting to a historical rate base balance to determine cost recovery in rates is not appropriate.

[30] Staff/1200, Moore/4.

*Adjustment 8.18, Wildfire Restoration Costs Deferral Amortization*

*a. Summary of Updates and Corrections*

**Q. Has an update been made to Adjustment 8.18, Wildfire Restoration Costs Deferral Amortization?**

A. Yes. While reviewing this adjustment for the various issues raised by parties in preparation of this reply filing, a formulaic error was identified on page 8.18.1 of the workpapers for this adjustment. On page 8.18.1, the formula intending to pull in the opening balance for October 2020 was deleted. The formula should be pointing to the ending balance from the September 2020 row immediately above it. In its reply filing, the Company has restored this formula. This correction increases the total amount for amortization by approximately $718,000 on an Oregon-allocated basis.

*b. Response to Staff's Adjustments*

**Q. Have you reviewed the proposed adjustments presented by Staff witness Mondragon?**

A. Yes, I have. My testimony will focus on proposed adjustments to the calculation of the amortization of wildfire restoration costs. While I also disagree with the proposed sharing mechanism proposed by Staff, that issue will be discussed in greater detail by Company witness McVee.

**Q. Which of the six proposed adjustments to the calculation of the amount for amortization does the Company accept?**

A. The Company accepts the following adjustments identified through the discovery process:

1) Reduction to deferred O&M by $573 for transactions recorded to the wildfire restoration order in error as identified in OPUC Data Request 587.
2) Removal of $1,361 in rate base that was included in the Base Period data of this case and should have been removed as identified in OPUC Data Request 588.
3) Offset the deferred revenue requirement of new plant by the revenue requirement of damaged net plant removed as identified in OPUC Data Request 584.

Furthermore, the Company accepts, in principle, Staff's proposed adjustment to remove depreciation expense incurred from September 14, 2021 through October 3, 2021, to reflect the brief period in time where the Company did not have authorization to defer costs to the wildfire restoration cost deferral account due to a delay in 2021 in filing for reauthorization of this deferral.

**Q. Please explain Staff's proposed adjustment to remove $150,000 of depreciation expense, and $155 of O&M expenses for unrecoverable transactions from September 14, 2021 through October 3, 2021.**

A. As Staff noted, the Company had applied to defer costs associated with the 2020 wildfires four times since 2020. The first deferral period was approved in Order No. 22-154, to be September 14, 2020 to September 13, 2021. In September 2021 however, an application to reauthorize the use of the deferral account approved under docket UM 2116 was filed late, which resulted in the second annual deferral period running from October 4, 2021 through October 3, 2022 in Order No. 22-140. In that order, it was noted that transactions recorded between the end of the first annual deferral period, and the subsequent deferral period were to be excluded. Accordingly, in Staff's review of the calculations supporting the amount of deferred 2020 wildfire

costs that the Company is seeking to amortize in this case, Staff has identified $150,000 of depreciation expense, and $155 of O&M expense attributable to transactions recorded during that gap period that Staff is recommending be removed from the total deferred amount to be amortized.

**Q. Do you agree with Staff's quantification of this proposed adjustment?**

A. No. First of all, I disagree with the removal of the $155 O&M expense as part of Staff's proposed adjustment for the purpose of reflecting unrecoverable amounts prescribed in Order No. 22-140. In OPUC Data Request 406, Staff asked for O&M costs recorded between September 14, 2021 through October 3, 2021. One month-end accrual for $155 was recorded in that period, but the Company further explained in its response to OPUC Data Request 406 that this accrual item was reversed on October 6, 2021. If the $155 accrual is removed, then the corresponding reversal should be removed as well.

As for the proposed depreciation expense adjustment, Staff calculated the "unrecoverable" depreciation expense as a full month of depreciation expense instead of only the depreciation expense associated with the specific number of days where deferral of costs was not allowed per Order No. 22-140. Order No. 22-140 reauthorized the use of deferred accounting for the costs associated with damage restoration from the 2020 wildfires for the 12-month period starting October 4, 2021, while reiterating that only costs from September 14 through October 3, 2021, could not be deferred. Therefore, the exclusion of depreciation expense should only be for the 20 days between September 14, 2021, and October 3, 2021. Accordingly, the proper calculation of depreciation expense to be excluded from the deferral balance

should start with the amount calculated by Staff for the full month, and then should be pro-rated to only reflect 20 days. With the pro-ration calculation added, the amount of Oregon-allocated depreciation expense excluded from the deferral balance in reply is approximately $97,000, as opposed to the $150,000 proposed by Staff witness Mondragon.

**Q. Which of Staff's proposed adjustments does the Company not agree with?**

A. The Company does not agree with Staff's proposed adjustment referred to as the "Employee Convenience Supplies" reduction to expense in the amount of approximately $3,000.

**Q. What does this $3,000 adjustment represent?**

A. In examining the Company's response to OPUC Data Request 587, Staff identified approximately $6,000 of expenses recorded as "employee convenience supplies". In response, the Company clarified that these expenses charged to the wildfire restoration orders under the "employee convenience supplies" cost element relate to refreshments, ice, and snacks and, as such, should more appropriately have been coded to cost element (or G/L) 503115, On-site Meals & Refreshments. The Company also affirmed that these were valid restoration costs.

However, Staff witness Mondragon asserted that because On-site Meals & Refreshments expenses are typically subject to a 50 percent exclusion from rates, that these amounts deferred in docket UM 2116 should also be reduced by 50 percent.

**Q. Do you agree that these costs should be reduced by 50 percent as Staff proposes?**

A. No. As discussed above in the section of my testimony addressing Staff's proposed additions to Adjustment 4.9, Meals & Entertainment Adjustment, the Company

routinely excludes storm and fire restoration work-related amounts from the M&E reduction adjustment. This treatment had been implemented consistently as in the Company's previous two GRCs, and in its direct filing when adjustment for total M&E expenses reflected in the test period. Providing meals during emergency situations like storm and fire restoration efforts is critical in facilitating efficient and prompt reconnection of electric service to customers, which the Company does not consider "discretionary". Having access to water and ice is important to the safety of the line crews working on the restoration project while working in the field.

***c. Response to AWEC's Adjustments***

**Q. Did other parties sponsor testimony addressing the amortization of wildfire restoration costs amortization?**

A. Yes, AWEC witness Lance D. Kaufman sponsored testimony addressing the wildfire restoration costs that the Company is seeking amortization of in this case.

**Q. Please summarize AWEC's primary position on amortization of wildfire restoration costs.**

A. AWEC's primary position is that: (i) the amortization of deferred costs should be disallowed in its entirety on the basis that these costs were the result of imprudent management and should not be recovered from customers; (ii) the cost of removal associated with retired assets be disallowed by "returning" the cost to accumulated depreciation and; (iii) a portion of the restoration capital costs be excluded from rates and rate base be reduced accordingly.

**Q. Please summarize any alternative recommendations made by AWEC with regards to wildfire restoration costs.**

A. With regards to the deferred costs, if the Commission approves amortization of some or all of the deferred costs under docket UM 2116, then AWEC has four alternative recommendations:

1. Cost of capital calculations for capital accrual in the deferral period should be aligned with the effective cost of capital in the period of accrual;
2. Interest accrual should compound annually, rather than monthly as reflected in the Company's proposed amortization calculation in its direct filing;
3. The deferral balance be reduced to reflect recovery of retired assets previously embedded in base rates (same recommendation as the third item proposed by Staff witness Mondragon, accepted by the Company as discussed above); and
4. Amortization of authorized recovery extended to five years, rather than three as proposed by the Company.

**Q. What is the Company's response to AWEC's primary recommendation with regards to docket UM 2116 costs?**

A. The Company disagrees with AWEC's primary recommendation in all regards for reasons I discuss below. Please also refer to the direct testimony of Company witness Berreth and reply testimony of Company witness McVee respectively for further details in defense of the prudence of these costs and the appropriateness of allowing the Company to amortize these deferred costs in rates.

**Q. Conceptually, is AWEC's proposed adjustment appropriate?**

A. No, it is not. First, and as discussed in the reply testimony of Company witness

McVee, the restoration of service to customers after a major disruption event is always a necessary priority, and the Company's view is that costs associated with the restoration of service to customers should be allowed in rates.

**Q. Please describe the cost components associated with the 2020 wildfire restoration efforts.**

A. Broadly speaking, the 2020 wildfire efforts resulted in three category of costs that the Company seeks recover of. These categories are:

1. Capital investments in newly installed assets
2. Undepreciated net value of damaged assets
3. Removal costs of damaged assets

**Q. Please explain why each category of costs should be recoverable in rates.**

A. The cost of new assets installed after the fires were necessary to ensure customers' electric service is restored. Moreover, the newly installed assets will also be in-service to serve customers over the life of the newly installed assets. Because these assets are useful and are in-use to serve customers, the cost of that new capital investment is justifiably borne by customers. To disallow any portion of the cost of the newly installed assets is unreasonable because it would result in the Company being afforded no opportunity to fully recover its costs associated with or earn a return on the newly installed assets that are needed to maintain service to customers and will be in place to provide service to customers on an on-going basis.

Disallowing recovery of the undepreciated value of the damaged assets is inappropriate even if assets are no longer used and useful to customers. While ORS 757.355 limits a utility's ability to include such amounts in rate base on which to earn

a return, it does not limit the utility's ability to recover the underlying cost of the assets. Consistent with Order No. 22-154 in docket UM 2116, the Company has isolated the undepreciated investment in plant no longer used and useful due to wildfire damage of or destruction to a regulatory asset. In this filing, the Company is only seeking to amortize the regulatory asset containing the damaged assets' net book value (NBV) and have not included the balance of the regulatory asset as part of rate base on which a return will be earned.

Finally, the costs of removal in question are prudently incurred costs required to remove the damaged assets and clear the areas for the installation of the new replacement assets. If the installation of the new assets for the purpose of restoring customer service should be deemed prudent, then the removal costs should be considered prudent as well and not be disallowed. Not removing and replacing the damaged asset was not an option.

**Q. Is AWEC's characterization of "group depreciation" accurate in recommending that the Company should reverse the impact of net cost of removal by increasing accumulated depreciation to hold ratepayers harmless?**

A. Not entirely. It is important to note that, in accordance with FERC guidance, group depreciation rates established in depreciation studies include an embedded component for cost of removal, such that depreciation expense recorded over the life of an asset group reflects an over-depreciation over time to account for the cost of removal for assets within an asset group. This embedded cost of removal component is similar to a "prepayment" of sorts such that customers benefiting from the use of the asset group pay for the cost of removal anticipated for assets within an asset group over the

time period when the group of assets is depreciated or used. The over-depreciation creates an incremental credit balance in rate base while the asset is still in-service. This incremental credit balance (i.e. a reduction to rate base) essentially "stores" the amounts collected for cost of removal, until any assets from the asset group is to be retired, or otherwise removed. Because the cost of removal was "prepaid", so to speak, the debit entry (i.e. increase to rate base) to record cost of removal "back to" accumulated depreciation reserves is more analogous to a "withdrawal" from this prepaid cost of removal balance that has been accruing in accumulated depreciation reserves, and not appropriately viewed as an "incremental cost" as AWEC portrays.

As a result, while the Company's cost of removal spend associated with the damaged assets does reduce accumulated depreciation (therefore increasing rate base), these costs are simply offsetting cost of removal accruals already accrued and already sitting in the accumulated depreciation of the asset group, AWEC's proposal is to increase accumulated reserve balances by the full amount of the removal costs incurred for 2020 wildfire restoration efforts, which is not an appropriate recommendation because it ignores the fact that the Company accrues for cost of removal through depreciation expense.

**Q. Why is AWEC proposing to disallow only a portion of the wildfire restoration newly installed asset costs from the 2020 wildfires?**

A. As discussed in AWEC witness Kaufman's testimony, "[o]ne consequence of the Labor Day Wildfires is that aged plant was replaced by new plant. The plant that was replaced had a remaining useful life and would have been replaced at some time in

the future."[31] Accordingly, AWEC designates the costs of new assets into two components—an "imprudent early retirement" of assets with remaining life and the replacement of assets that was prudently incurred at the end of that life.

Based on this designation, AWEC computed a ratio of test period undepreciated plant to gross plant, for distribution and transmission functions, respectively, and applied it to the respective distribution and transmission new capital investment to estimate a proposed disallowance for a portion of the $220 million of total investment in the newly installed wildfire restoration assets.

**Q. Do you have concerns with AWEC's calculation quantifying the portion of the wildfire restoration costs to be disallowed and corresponding reduction to rate base?**

A. Yes. First, to reiterate, the capital investment in the newly installed assets will benefit customers over their service lives and recovery of the cost of such investment over that service period is appropriate.

Regarding the quantification of AWEC's proposed adjustment, AWEC's recommendation is based on a view that the costs of newly installed assets were not incurred prudently because of the single jury verdict in the *James* case which does not cover all of the fires that caused the asset damage and new capital investment. Even if the concept behind AWEC's calculation was reasonable, the asset balance (i.e. $220 million of newly installed asset costs) on which the impact of AWEC's proposal was calculated far overstates the amount of the proposed disallowance.

[31] AWEC/200, Kaufman/018.

Lastly, to take the undepreciated plant ratios made up of all of the Company's transmission and Oregon distribution assets and use those ratios to determine the percentage of damaged assets that were "prematurely retired" is flawed. For example, due to the magnitude of the Company's capital program over the last several years, transmission plant placed into service outside the state of Oregon that would have incurred very little depreciation to-date due to its young age is skewing AWEC witness Kaufman's 78 percent calculation for the transmission portion of his proposed disallowance. These assets have no association with the assets that were damaged in the wildfires yet AWEC witness Kaufman's approach to derive a percentage of undepreciated plant contemplates these assets. To argue that percentage is representative of the population of damaged assets that were "prematurely retired" is illogical.

**Q. If the Commission does approve in part or in full the amortization of the deferred costs from 2020 wildfires, which of the proposals under AWEC's alternative recommendations does the Company agree with?**

A. Two of AWEC's recommendations have been incorporated in the calculation of the Wildfire Restoration Costs Deferral Amortization adjustment in reply. The Company agrees that it is reasonable for cost of capital calculations for capital accrual in the deferral period to be aligned with the effective cost of capital in the period of accrual. In reply, the revenue requirement of capital costs deferred in Year 1 and Year 2 (i.e. 2021 and 2022) is calculated by applying the docket UE 374 approved WACC (approved in 2021). Starting in Year 3 (i.e. 2023), the revenue requirement of capital costs deferred is calculated by applying the docket UE 399 approved WACC.

The Company has also included a calculation to offset the deferred revenue requirement of new plant by the revenue requirement of damaged net plant removed as identified in OPUC Data Request 584. This adjustment was also discussed in the testimony of Staff witness Mondragon.

**Q. Which aspect of AWEC's alternative recommendations with respect to wildfire restoration cost amortization does the Company take issue with?**

A. AWEC proposes changing the interest calculation component in the deferral balance calculation to either compound interest annually or adjust the calculation of the monthly interest rate to account for monthly compounding. As presented in the Company's direct filing, AWEC takes issue with the monthly compounding of interest over time, arguing that monthly compounding of interest results in the Company accruing more interest over the course of a year than the annual approved rate, be it the rate of return, or the modified blended treasury rate. The final recommendation AWEC proposed was to extend the amortization over five years, instead of three years as proposed by the Company.

**Q. Does the Company agree with the proposed modification to the interest expense calculation of the wildfire restoration cost deferral?**

A. No. The accrual and amortization schedule, including the interest accumulation calculation have been prepared in a consistent manner as with all deferral calculations the Company previously filed, including the WMVM mechanisms, and the WMP AAC mechanisms. The same interest calculation formula has also been applied to amortization of deferral items approved in previous GRCs, including a myriad of deferrals for which amortization was approved in docket UE 399, such as docket

UM 1964 (Transportation Electrification Program), docket UM 2134 (Cedar Springs II), docket UM 2186 (TB Flats), docket UM 2167 (Renewable Energy Credits from Pryor Mountain), docket UM 2142 (Cholla Unit 4-Related Property Tax Expense), and docket UM 2201 (Fly Ash Revenues deferral).

**Q. Is there any prescriptive guidance from the Commission that would indicate that monthly compounding of interest is not allowed?**

A. Not that I am aware. Pursuant to ORS 757.259, subsection 4 establishes that "the commission may authorize deferrals…beginning with the date of application, together with interest established by the commission." Docket UM 1147, Staff Request to Open an Investigation Related to Deferred Accounting, then set forth further guidelines on what the proper interest rate to be applied to utilities' deferred accounts should be. Based on my understanding of the various orders in docket UM 1147, it appears that the appropriate interest rates for deferral balances were established with the intention of compensating utilities for the financial risks borne by the utility for delayed recovery of costs. In other words, until the cost outlay is recoverable from customers, the Company is bearing the costs to finance those expenses. Accordingly, the compensation for this risk, in the form of interest accrual, can reasonably be expected to mimic the reality faced by the Company, which most frequently is an environment where monthly compounded interest is the norm for most sources of financed funds. There is also no mention that I am aware of that precludes the calculation of interest accrual on deferral balances from being compounded monthly.

**Q. Please summarize your recommendations regarding AWEC's proposals related to wildfire restoration costs.**

A. I recommend that AWEC's primary recommendation be rejected on the basis that the restoration costs deferred under docket UM 2116 were prudently incurred to ensure customers would continue to receive electric service. Additionally, customers will benefit on an ongoing basis from the newly installed assets over the assets' service lives.

In the event the Commission determines that amortization of these deferred amounts should be granted, the Company has reflected in its reply filing AWEC's recommendation regarding cost of capital alignment and inclusion of an offset to deferred costs for the revenue requirement of damaged assets previously collected in rates.

***Other Proposed Rate Base Adjustments***

***a. WMP AAC True-Up***

**Q. Please describe the adjustment of $2.4 million of WMP plant back into rate base as proposed by Staff witness Mondragon.**

A. In this GRC, the Company has made a proposal to consolidate all wildfire mitigation capital project costs to be recovered in the WMP AAC at the fully capitalized capital project costs, inclusive of indirect loadings, for wildfire mitigation capital projects included in ADV 1529 (incremental wildfire mitigation capital projects placed in-service after December 2022 through May 2023), as well as wildfire mitigation capital projects placed in-service prior to December 2022. Accordingly, in the Company's direct filing, all wildfire mitigation capital project costs placed in-service

through the Base Period (12 months ended June 2023) were removed from rate base. Staff disagrees with the Company's proposal to reflect the fully capitalized capital project costs for WMP capital assets in the WMP. Specifically, Staff continues to support the settlement outcome from ADV 1529, where to alleviate any concern for potential double-recovery of capitalized overheads/indirect loadings assumed in the most recently approved GRC rates, and the incremental project costs being reflected in the WMP AAC, Staff and the Company agreed that the recovery of indirect loadings related to WMP capital projects be postponed until a subsequent GRC. For this reason, Staff is proposing to add back $2.4 million to rate base, representing the net plant balance associated with indirect loading amounts excluded from recovery though the WMP AAC per settlement terms in ADV 1529.

**Q. Does Staff oppose the Company's proposal to consolidate wildfire mitigation costs into the WMP AAC in its entirety?**

A. No. Staff did not voice opposition to consolidating the fully capitalized project costs for WMP capital projects placed in-service prior to December 2022, that is currently being recovered in base rates, into the WMP AAC for recovery. Staff's proposed adjustment of $2.4 million only represents the identified indirect loading amounts from the 2023 WMP AAC (ADV 1529), for projects placed in-service after December 2022, through May 2023.

**Q. What reasoning did Staff provide in support of continuing to keep the recovery of indirect costs associated with WMP capital in base rates?**

A. Staff reiterates the settlement terms from ADV 1529, but no other rationale was offered.

**Q. Is it the Company's position that the proposed consolidation of WMP capital costs to the WMP AAC filing is consistent with the spirit of the settlement terms from ADV 1529?**

A. Yes. The Company's proposal for indirect loadings to be consolidated and included into the WMP AAC rate is only for each instance in which the Company files a GRC to update base rates. In WMP AAC years in between rate case years, the Company continues to agree to exclude indirect loadings from the incremental wildfire mitigation capital project costs from WMP AAC filings as a way to preclude any concerns on potential double-recovery between capitalized overheads/indirect loadings assumed in approved GRC rates, and the incremental recovery of wildfire mitigation project costs through WMP AAC filings. This concern for a potential double-recovery across filings was the primary reason Staff and the Company made the settlement concession to exclude indirect loadings from rates set through its 2023 WMP AAC update. However, at no point were these costs determined to be imprudent or unrecoverable—only that recovery be delayed until the next subsequent GRC. To that extent, the Company's proposal does honor the agreement, by continuing to delay recovery of indirect loadings until a base rate change happens with a subsequent rate case. The only difference is that the recovery of the lagging indirect loading costs will not be part of base rates; but rather through a simultaneous true-up of the AAC at the same time new base rates take effect in a subsequent GRC.

**Q. How does the Company's proposal improve the administrative processes around cost recovery of WMP capital?**

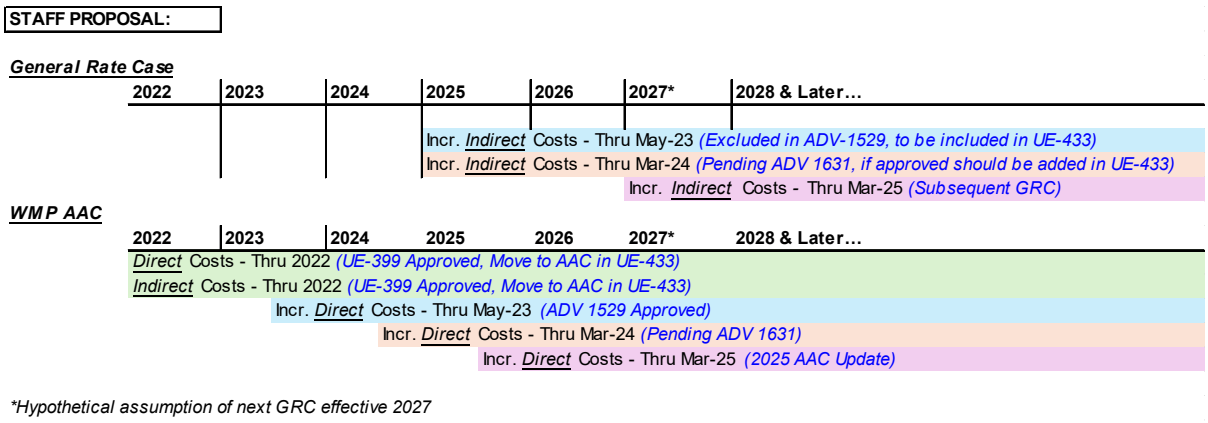
A. As currently approved, costs for wildfire mitigation capital projects placed in-service

prior to December 2022 are approved for recovery in base rates from the settlement outcome from docket UE 399. Incremental wildfire mitigation capital project costs, less indirect loadings, are being recovered under the AAC, and indirect loadings would be recovered in base rates at each subsequent GRC. The result is a convoluted, piece-meal approach to the recovery of wildfire mitigation capital project costs, that requires the Company to implement and maintain on-going tracking for a subset of indirect loading costs embedded in numerous capitalized assets, which the Company does not currently track separately. The Company's proposal simplifies the recovery of these costs and helps to reduce the administrative burden for the Commission's review by consolidating all fully capitalized costs for wildfire mitigation capital projects into one recovery mechanism at each future instance when base rates are reset. Indirect loadings for incremental wildfire mitigation projects will only need to be separately tracked in between GRC test years.

**Q. Can you illustrate this streamlining of administrative processes with an example?**

A. Yes. The cost recovery processes and timing for WMP capital cost recovery advocated for by Staff can be visualized in Figure B below.

**Figure B—Staff Proposal for WMP Capital Cost Recovery**




*Hypothetical assumption of next GRC effective 2027

**Q. What are some key complications of the processes advocated for by Staff?**

A. First and foremost, recovery for WMP capital projects is spread across two different filings, that are on two different cadences. Where the WMP AAC files each year, a GRC is not routinely scheduled in that way. The timing and interim tracking of what costs are reflected in which filing can become extremely challenging, as the years roll on, and more costs are added with each WMP AAC, and each subsequent GRC.

Moreover, Staff's advocated processes would capture all direct *and indirect* costs for WMP capital projects placed in-service prior to December 2022 for recovery through the WMP AAC (see green bars in Figure B), while for all years 2023 onwards (see blue, orange, and pink bars in Figure B), direct costs are included in the WMP AAC, while indirect costs are split off to be recovered under GRCs, resulting on-going tracking of portions of costs across two dockets, through multiple filings as the years progress.

**Q. Does the Company routinely track direct costs separately from indirect loadings?**

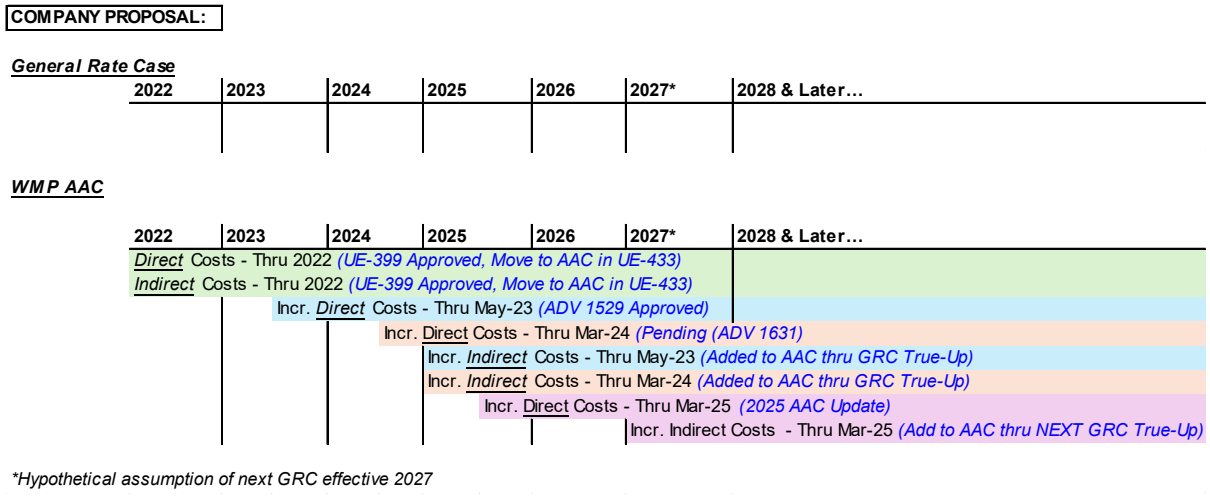
A. No. Consistent with generally accepted accounting principles and the CFR, Title 18,

Chapter I, Subchapter C, Part 101, Electric Plant Instruction 3, the Company does not continue to track direct versus indirect costs once an asset is capitalized. Capital projects, when completed and placed in-service, are capitalized to electric plant in-service balances at the fully capitalized cost to bring the project into service. To track indirect costs on an on-going basis would require the Company to implement separate books of records and deviate from generally accepted practices and FERC accounting guidance.

**Q. How does the Company's proposed processes circumvent these complications evident in Staff's advocated processes?**

A. The Company's proposed processes and timeline for cost recovery is presented in Figure C below.

**Figure C—Company Proposal for WMP Capital Cost Recovery**




The Company's proposed processes will result in the exclusion of 100 percent of wildfire mitigation capital project costs from base rates in GRCs. This means that going forward, Staff would only need to verify in GRC proceedings that all WMP AAC-eligible capital projects have been removed from the test period of each rate

case, and would not also have to dedicate time to review the amount of indirect loadings that has been queued up since a previous GRC.

Further, the Company's process does not require tracking of indirect costs on an on-going basis. With a simultaneous WMP AAC true-up to add indirect loadings into the WMP AAC, 100 percent of WMP AAC-eligible capital costs will be consolidated for recovery purposes with base rate changes effective at the time a GRC is approved.

Most importantly, comparing Figure C (Company proposal), and Figure B (Staff proposal), one can see that the recovery of indirect loading costs is still "held back" until a subsequent GRC under the Company's proposal in this case. In other words, there is no relatively accelerated recovery of indirect cost, compared to the currently approved processes. In this sense, the Company's proposal continues to honor the spirit of the settlement terms in ADV 1529 and continues to sidestep any concerns for potential double-recovery of capitalized costs in between GRCs.

**Q. What is your recommendation regarding Staff's proposed $2.4 million adjustment for WMP capital rate base, and the associated implications on Staff's opposition to the Company's proposed changes to the WMP capital cost recovery processes?**

A. I recommend Staff's proposed $2.4 million adjustment be rejected. The Company maintains that its proposed WMP AAC True-Up to reflect consolidation of fully loaded capital costs for WMP capital projects into the AAC at each instance when new base rates are approved through a GRC should be approved. Staff relies on the settlement outcome of ADV 1529 as justification to maintain current processes, but

the current processes are unnecessarily complex, require implementation of additional tracking capabilities in the Company's processes, and spread the Commission's review of PacifiCorp's WMP capital costs across multiple filings. While a settlement concession was made in ADV 1529, it should not preclude parties from working collaboratively, to critically assess processes and develop improvements that would allow for maximum efficiency and prevent unnecessary administrative burdens for all parties involved.

***b. Wildfire Mitigation Transmission Capital Allocation***

**Q. Did Staff make any recommendation on the allocation of wildfire mitigation transmission capital?**

A. Yes. Staff recommends that the Commission adopt an allocation across the states for wildfire mitigation transmission costs at a percentage that represents the actual investments the Company has made in Oregon's and other state's High Fire Consequence Areas. Staff recommends the Commission use this direct assignment until wildfire mitigation investments are approximately equal to the SO factor of 27.43 percent in Oregon, compared to the total wildfire transmission capital investments. Staff states that the purpose of this adjustment would be to incent the Company to make wildfire investments proportionally across the states.

**Q. How do you respond?**

A. First and foremost, the Company's investment in wildfire mitigation transmission capital should not be proportional across the states, but rather as necessary in response to the wildfire risk in each area. For a discussion of how the wildfire

mitigation transmission capital investments included in this case benefit Oregon's customers, please refer to the direct testimony of Company witness Berreth.[32]

Secondly, Staff's recommended allocation of transmission wildfire mitigation capital investments runs completely afoul of the Commission-approved allocation methodology, which specifies that transmission plant be allocated on the SG factor.

**Q. How are transmission investment costs allocated in Oregon rates, including this GRC?**

A. System-wide transmission costs are allocated on a SG factor of 26.884 percent, per the approved 2020 Protocol, and not on a SO factor basis as suggested to by Staff. All system transmission assets are allocated consistently, and appropriately in accordance with the Company's currently approved allocation methodology. While Oregon customers are paying for a portion (approximately 26.884 percent) of transmission assets across the entire system, customers in all other jurisdictions served by the Company are also paying approximately 73.116 percent of transmission assets across the system, including those located in Oregon.

***c. Klamath Transfer Costs***

**Q. Are there other adjustments in Tab 8 that you would like to discuss?**

A. Yes, in May of 2024, PacifiCorp was informed by the Klamath River Renewal Corporation (KRRC) that the Company would need to provide $15 million in contingency funds, as per the December 2022 Memorandum of Agreement, to support the removal of the Klamath Dams. The Oregon-allocated portion of this is approximately $4.0 million, and PacifiCorp will be seeking to include it in the

[32] PAC/1400, Berreth/6.

regulatory asset that was described in my direct testimony and identified in page 8.20 of Exhibit PAC/1702.

**Q. Will PacifiCorp be seeking to adjust the revenue requirement for this amount in this proceeding?**

A. Not at this time. PacifiCorp is planning to file a supplemental request jointly with the KRRC in docket UE 219 to use the accrued interest identified in that proceeding to fully offset the contingency funds. However, if the accrued interest is not used to fully offset the contingency funds, the requested annual amortization of the Klamath transfer costs regulatory asset will increase by approximately $1.2 million per year.

## F. TAB R – Reply Adjustments

**Q. Please describe the new Tab R included in Exhibit PAC/3302.**

A. Tab R incorporates adjustments to the case that are presented individually for ease of calculation and visibility. The following adjustments have been added to this section of the exhibit.

- Adjustment R_1, Capitalized Officers' Incentives Adjustment
- Adjustment R_2, Remove Customer Service System

***Adjustment R_1, Capitalized Officers' Incentives Adjustment***

**Q. Please describe Staff's proposed Capitalized Incentives Adjustment.**

A. Staff proposes to remove $18.7 million on an Oregon-allocated basis from rate base for the total officer and non-officer incentives based on the amount of AIP and Bonuses awards for NEOs an non-officer employees capitalized over the last 20 years (2004 - 2024). A corresponding adjustment to depreciation expense is also proposed associated with the removal of capitalized incentives from rate base proposed by

Staff. Staff's proposed adjustment differs from the currently approved adjustment to reflect removal of capitalized incentives in two significant ways: 1) the number of years' data relied upon to calculate the reduction to rate base for capitalized incentives, and 2) the inclusion of non-officers' incentives to the calculation of the reduction to rate base.

**Q. What justification or reasoning has Staff provided in support of deviating from the previously ordered adjustment methodology?**

A. Staff witness Yamada states that "While the most recent assets will have experienced the least depreciation (and therefore have the greatest impact to the Company's rate base), it is possible that the Company's Test Year rate base includes capitalized incentives associated with assets that were put into service decades ago."[33]

Later, Staff witness Yamada states "Staff finds that all of the Company's non-officer incentives (including the AIP and Bonus amounts) should be treated as merit-based incentives which are subject to 50 percent exclusion from customer rates. Consequently, all non-officer capitalized incentives present in rate base should be reduced by 50 percent."[34]

**Q. Was Staff's proposed adjustment to capitalized incentives consistent with the adjustment adopted in docket UE 374 and re-adopted in docket UE 399?**

A. No. In the Company's docket UE 374, the Commission adopted Staff's recommended adjustment for capitalized officer incentives. Based on Staff's testimony in docket UE 374, Staff witness Heather Cohen stated that "Staff typically disallows the total

[33] Staff/2000, Yamada/14.
[34] Staff/2000, Yamada/14.

number of officer incentives capitalized in plant since the last rate case."[35] In docket UE 374, rates were requested to be effective January 2021, and the most recent GRC previous to it had rates effective January 2014. Based on that, Staff's adjustment in the docket UE 374 sought to remove capitalized incentives between years 2015 through 2020 inclusive. For more recent years where actual capitalized officers' incentives amount were not yet known or were not expected to be known in time to meet filing deadlines, Staff used an alternative method by developing a historical average as a placeholder. For example, to obtain the amount for 2020, the average of five historical years 2015 to 2019 was used.

Applying the same reasoning in docket UE 399, the Company's most recently concluded GRC, rates were requested to become effective January 1, 2023. The previous GRC (UE 374) was effective 2021, as described above. Accordingly, in docket UE 399, the year for which capitalized incentives disallowance was considered was the one year in between 2021 and 2023, which was 2022. This adjustment was included in the settlement revenue requirement ultimately approved in docket UE 399.

In the current GRC, Staff is proposing a removal of capitalized officers' *and non-officer* incentives capitalized for *all years back through 2004*. This approach is inconsistent with the adopted adjustment in docket UE 374 which was also applied again in docket UE 399, in that it deviates from Staff's approach to disallow the total amount of only officers' incentives capitalized in plant since its most recent previous case, and it reaches well beyond the number of years for which capitalized officers'

[35] Docket No. UE 374, Staff/400, Cohen/10.

incentives were disallowed compared to the last two rate cases (dockets UE 374 and UE 399).

**Q. Should non-officer incentives be included in the capitalized officer incentives adjustment?**

A. No. For starters, NEOs incentives have been specifically ordered to be excluded from rates, and the Company has continued to make the calculations to ensure this practice. While the Company did not initially prepare an adjustment for officer's capitalized incentives, the Company agreed in its response to OPUC Data Request 481 that one needed to be provided and would produce an adjustment in its reply filing to reflect the adjustment to capitalized officers' incentives. NEOs compensation information is reported in the Company's Form 10k and is easily traceable to enable the creation of the Capitalized Officer's Incentives adjustment. On the flip side, non-officers' incentives data does not have the same level of clarity or traceability that would allow a similar adjustment to be calculated appropriately. Applying a blanket reduction to all AIP and Bonuses awarded to non-officers is inappropriate as non-officer employees are not all subject to capitalization, nor do the employees who may be subject to capitalizing labor costs charge 100 percent of their time to capitalized projects. While tracking the labor costs, and how much of it is capitalized for one (non-officer) employee is possible, tracking the same information to that level of detail for a pool of almost 5,000 employees is simply not feasible. Because of this, there is no way to accurately determine how much of non-officer employees' incentives and merit-based bonuses have been capitalized over time. To assume all non-officers' AIP and bonuses are merit-based, is also not an accurate assumption.

Historically, the Company has also not been required to attempt this calculation. Citing back to Staff witness Cohen in docket UE 374, whose adjustment was adopted by the Commission and established the precedent for the removal of capitalized incentives from rates, "Staff typically disallows the total number of *officer incentives* capitalized in plant since the last rate case."[36]

**Q. Does the Company agree that an adjustment to capitalized officers' incentives should be included in accordance with what was adopted in docket UE 374, in Order No. 20-473.**

A. Yes. Accordingly, the Company has calculated in Adjustment R_1, Capitalized Officers' Incentives adjustment to remove the estimated capitalized officers' incentives balance for 2024. Similar to Staff's alternative methodology in the previous case for amounts not yet known, the Company applied a historical average calculated using five historical years data from 2019 through 2023 to estimate the 2024 capitalized incentives amount. The Company then removed the Oregon-allocated portion of this estimated 2024 capitalized incentive balance, along with an imputed depreciation expense from Test Period results. By applying a methodology consisting with that of the adopted adjustment proposed by Staff in docket UE 374, the Company calculated an adjustment that resulted in a net decrease in Oregon revenue requirement of approximately $10,000.

***Adjustment R_2, Remove Customer Service System***

**Q. Please describe Adjustment R_2, Remove Customer Service System.**

A. The Company's direct filing included a Customer Service System capital project.

[36] Docket No. UE 374, Staff/400, Cohen/10 (emphasis added).

However, since the time of the direct filing, the Company has become aware that this project will not be placed in-service by January 1, 2025, and as a result, the project is being removed from Test Year rate base. This adjustment reflects the removal of the project and reduces Oregon revenue requirement by approximately $6.3 million.

## G. Rate Base Methodology

**Q. Did Staff propose changes to the rate base methodology utilized in this case?**

A. Yes. In this proceeding, Staff is advocating for the implementation of a rate base methodology Staff describes as a "13-month average-of-monthly averages" (AMA) for 2025 for electric plant in-service (EPIS) rate base[37], as opposed to the Company's use of a 2024 end-of-period (EOP) EPIS rate base methodology, which Staff calls a "pre-test period snapshot (PTPSS)". Staff supports their proposal by stating the AMA method has been commonly used by the Commission for decades and cites a series of orders dating back to the 1970s. Staff claims that the proposed methodology for calculating rate base would be similar to what Staff proposed in PacifiCorp's general rate case, docket UE 210.

**Q. Is Staff's characterization of their proposed rate base methodology as an AMA accurate?**

A. No. Staff's description of their proposed methodology as an AMA methodology for 2025 is inaccurate because Staff's proposal actually mixes an AMA approach for accumulated reserves with an EOP approach for gross plant. Specifically, Staff's approach walks forward depreciation and amortization reserves into the test year 2025 and calculates an average-of-monthly-average balance of reserves, while

[37] Staff/1900, Stevens/26.

holding gross plant balance constant at 2024 end-of-period levels, without including incremental additions to gross plant that will be placed in-service throughout test year 2025. A true AMA 2025 methodology for EPIS rate base calculations would see all relevant components associated with EPIS (i.e. depreciation and accumulated reserves, and accumulated deferred income taxes) concurrently be walked forward into 2025, and then an average-of-monthly-averages be calculated based on the fully walked forward balances with all aspects considered. Staff's modified AMA approach creates a mismatch of rate base treatment between gross plant and accumulated depreciation reserves, which is problematic for reasons I will explain further in my testimony.

**Q. Is Staff's representation of the Company's proposed rate base methodology accurate?**

A. No. Staff's description of the Company's rate base calculation is that "[PacifiCorp's] rate base calculation is based on EPIS capital additions up to December 31, 2024. Similarly, all depreciation, amortization, and accumulated depreciation is stepped forward to December 31, 2024."[38] This is an incomplete description. The Company layers on to the end-of-period balances up through December 31, 2024, an incremental adjustment to reflect an annualized level of depreciation and amortization expense, and a corresponding incremental credit to depreciation and amortization reserves. In other words, the Company's rate base methodology in calculating EPIS and associated balances reflect not just a "snapshot" at December 31, 2024, but in fact includes the annualized effect of depreciation and amortization, giving customers the

[38] Staff/1900, Stevens/26.

rate base benefit of a higher depreciation and amortization reserve for the annualization adjustment. Associated deferred tax balances are also consistently established on this annualized 2024 basis.

**Q. Can you illustrate "the annualized effect of depreciation and amortization", as referenced above, and clarify how that differs from Staff's expressed understanding of the EPIS rate base methodology the Company is using?**

A. Yes. Please refer to Figure D below summarizing hypothetical EPIS and associated depreciation balances in a scenario where gross plant balances start at $10 million. Mid-way through the year, a $500,000 capital project was added to rate base.

**Figure D—Annualized EOP Methodology**

**Annualized End-Of-Period Methodology**

| | | Additions | Gross Plant | Depreciation | Accum. Reserves | Net Plant |
|---|---|---|---|---|---|---|
| Pre-Test Year | January | - | 10,000,000 | 250,000 | (250,000) | 9,750,000 |
| | February | - | 10,000,000 | 500,000 | (750,000) | 9,250,000 |
| | March | - | 10,000,000 | 500,000 | (1,250,000) | 8,750,000 |
| | April | - | 10,000,000 | 500,000 | (1,750,000) | 8,250,000 |
| | May | - | 10,000,000 | 500,000 | (2,250,000) | 7,750,000 |
| | June | 500,000 | 10,500,000 | 512,500 | (2,762,500) | 7,737,500 |
| | July | - | 10,500,000 | 525,000 | (3,287,500) | 7,212,500 |
| | August | - | 10,500,000 | 525,000 | (3,812,500) | 6,687,500 |
| | September | - | 10,500,000 | 525,000 | (4,337,500) | 6,162,500 |
| | October | - | 10,500,000 | 525,000 | (4,862,500) | 5,637,500 |
| | November | - | 10,500,000 | 525,000 | (5,387,500) | 5,112,500 |
| | December | - | 10,500,000 | 525,000 | (5,912,500) | 4,587,500 |
| | **12 Months Ended December** | | | **5,912,500** | | |
| | Depreciation Rate (Monthly) | | | 5% | | |
| | Actual Depreciation Expense | | | 5,912,500 | per table above | |
| | Annualized Depreciation Expense | | | 6,300,000 | Depr. Rate x EOP gross plant x 12 | |
| | Annualization of Reserves | | | (387,500) | delta - annualized and actual Depr. Exp. | |
| | Annaulized EOP Reserves | | | (6,300,000) | EOP reserve + above | |

In the scenario summarized by Figure D, EPIS rate base balances under a "PTPSS" methodology as described by Staff, and an annualized EOP methodology being used by the Company contrast as follows:

| | PTPSS | Annualized EOP |
|---|---|---|
| Gross Plant | 10,500,000 | 10,500,000 |
| Depreciation Reserve | (5,912,500) | (6,300,000) |
| Pre- Test Year Net Plant | 4,587,500 | 4,200,000 |

Under the Company's annualized EOP methodology, Net Plant balance is lower than would be determined under the "PTPSS" methodology that Staff thinks the Company uses,[39] because accumulated reserves reflect an incremental credit for the annualization effect of depreciation, and net plant balance ends up being smaller than a straight "point in time snapshot" balance under the "PTPSS" methodology.

**Q. Staff discusses PacifiCorp's historical approach to calculating rate base. Can you please provide additional detail regarding the evolution of the EPIS rate base calculation methodology used by PacifiCorp for ratemaking purposes?**

A. Yes. In docket UE 210, with test period calendar year 2010, the Company filed a GRC with all rate base calculated on a 13-month simple average basis and included in its rate request capital additions through the test period. Staff took issue with inclusion of capital additions through the test period, claiming that including them would be a violation of ORS 757.355 ("Costs of property not presently providing utility service excluded from rate base"), and Staff wanted the pro forma capital additions through the rate effective period removed. The Company filed rebuttal testimony strongly objecting to the proposal. The issue did not get adjudicated in that case, because docket UE 210 was ultimately settled through stipulation.

Because of the controversy surrounding the application of ORS 757.355 and whether capital projects placed in-service through the test period would satisfy the

[39] Staff/1900, Stevens/26.

"used-and-useful" standard, the Company modified its rate base calculation approach for EPIS in its subsequent GRC, docket UE 217 (with test period calendar year 2011), to not include any cost components related to EPIS capital additions anticipated to be placed in-service past the rate effective date. EPIS balances in docket UE 217 were established using an EOP rate base, with inclusion of pro forma capital additions up through the rate effective date, while non-EPIS rate base items continued to be calculated using a 13-month simple average rate base calculation through the test period (i.e. no change to non-EPIS rate base methodology from docket UE 210). The EPIS calculations in docket UE 217 also wholistically included an annualized depreciation/amortization expense and a top-up of accumulated depreciation/amortization reserve to match the annualized depreciation/amortization expense.

The Company designed this methodology as a balanced approach to synchronize the various EPIS costs items (i.e. gross plant, depreciation/amortization expense and depreciation/amortization reserves) to a consistent point in time so that they are matched with each other, while avoiding another dispute with Staff over the interpretation and application of ORS 757.355 given the experience in docket UE 210. Docket UE 217 was settled before Staff filed testimony, and the final order in that case did not seem to suggest any controversial exchanges between parties on the topic of EPIS rate base. Since docket UE 217, the Company has been consistent in filing rate cases using the same EPIS rate base methodology. The Company has not encountered any objection from Staff regarding the Company's rate base treatment

for over a decade, over which time five rate cases have been filed and decided, including a fully litigated GRC in docket UE 374.

**Q. What is the effect of Staff's proposed methodology in this case?**

A. The effect of Staff's adjustment is simply to include an additional half year of accumulated depreciation reserve into rates, by only walking depreciation reserves into the rate effective period. This understanding is confirmed by the mathematical derivation of the impact of Staff's proposed adjustment, where Staff witness Stevens applied a simplified total-Company, all-function composite depreciation rate to the 2024 "net plant balance" and then divided the outcome in half to estimate the incremental depreciation reserve of Staff's so-called "AMA 2025" methodology.

**Q. Is Staff's calculation of the impact to revenue requirement in this case for Staff's proposed change in rate base methodology correct?**

A. No. Staff's calculation of the estimated rate base adjustment estimates the AMA reserve impact by multiplying a composite, all-function depreciation rate to what Staff states is the "2024 net plant balance". Depreciation expense should be calculated based on gross plant balances, and not net plant balances. Furthermore, the balance that Staff has reflected in its calculation is the sum of gross plant, and depreciation reserves, but Staff neglects to include the amortization reserve balance, which makes the 2024 net plant balance that Staff is using as the basis to estimate its adjustment incomplete. Also, a composite, all-function depreciation rate is a grossly simplified way to estimate depreciation expense. The Company calculates depreciation expense in cases using depreciation rates, ranging from 1.090 percent to 13.675 percent in this GRC, that are specific to balances based on function and

allocation factor. Further, because Staff ignored the annualization adjustment included in the Company's filed EPIS rate base balances, Staff's adjustment effectively duplicates that effect. To properly walk forward reserves into 2025 average-of-monthly-average balances, the annualization effect included in the Company's direct filing needs to first be eliminated and backed out of the reported 2024 EPIS balances reported in the Company's direct filing. Changes to test period accumulated reserve balances also affect allocation factors that rely on net plant balances, such as the System Net Plant factor, and a variety of functional net plant-based allocation factors such as the SNPD factor and have spill-over affects across many balances within the revenue requirement calculation. Finally, Staff's proposed adjustment also does not reflect any necessary concurrent adjustments to associated tax balances required to ensure compliance with the tax normalization rules.

**Q. Is Staff's proposed rate base calculation for EPIS in this case reasonable?**

A. No. As explained above, Staff's "AMA" methodology is a blending of year-end 2024 gross plant with 2025 average-of-monthly-average reserves, which inappropriately creates a mismatch between rate base components and does not reasonably reflect PacifiCorp's rate base during the Test Period.

**Q. Please explain your concerns with the mismatch created by Staff's adjustment.**

A. By only accounting for changes into the Test Period of accumulated reserves in the case, but not making similar changes to gross plant balances, Staff's adjustment is contrary to the matching principle. In general, the matching principle is a ratemaking principle that states that the costs incurred during a period should be matched against the revenue generated in the same period. In the context of a general rate case, this

principle requires a time period "matching" of revenues, costs and rate base balances used in the calculation of the revenue requirement. Staff's proposal to exclude incremental gross plant for assets placed in-service into the 2025 rate effective period effectively keeps the gross plant and accumulated deferred income tax balances at year-end 2024 levels. On the flip side, accumulated depreciation reserve on existing plant continues to increase through the end of the 2025 rate effective period, and is then averaged, which takes the accumulated reserves component of EPIS rate base forward into 2025 levels. This results in a mismatch between gross plant and accumulated deferred income tax (reported at 2024 levels), and accumulated reserves (reported at 2025 levels).

Staff's opinion is that plant placed in-service past the rate effective date is not compliant with ORS 737.355, in that those plants are not considered presently used and useful to customers. Although the Company disagrees with Staff's interpretation,[40] in response to Staff making this argument in docket UE 210, the Company proposed to cap EPIS rate base additions as of the day immediately prior to rates becoming effective, and simultaneously synchronized accumulated reserves and depreciation expense levels at that same point in time. The Company's approach adheres to the matching principle, and balances the Company's ability to recover costs of investments on a timely manner with Staff's interpretation of ORS 757.355.

[40] I note that inclusion of incremental additions to gross plant after the rate effective date has historically been allowed for ratemaking purposes in the Company's other jurisdictions, including Utah, Wyoming, California, and most recently Washington.

**Q. Staff states "…that retail customers are paying for depreciation expense that occurs in 2025 but do not see any benefit of those payments in net plant and the return associated with that net plant."[41] How do you respond?**

A. This is not entirely correct. The Company's calculation of depreciation expense only reflects annualized amounts for plant placed into service before the end of 2024. A corresponding 2024 annualized accumulated depreciation reserve amount is also included, meaning customers do see a corresponding benefit for any incremental depreciation expense that they are paying for in rates. Staff's proposal would artificially lower rate base by increasing accumulated reserves balances by forcing it forward to mid-2025 levels, and in doing so create a mismatch between the level of accumulated depreciation reserve in rates and the amount of gross plant in rates (i.e., assets going into service through 2024).

**Q. How do you respond to Staff's claim that the Company's relied upon EPIS rate base methodology results in the Company being "overcompensated" for the return the Company is allowed to earn in its rate base?**

A. Staff's statement that the Company's proposed EPIS rate base methodology would result in the Company being overcompensated is unfounded. Staff goes as far as to state that the Company's proposal "thwarts the purpose of ORS 757.355 in a sense that customer rates could end up higher than if ORS 757.355 does not exist",[42] which is blatantly wrong and only possible under Staff's flawed assumptions. An appropriately calculated AMA—one that includes forecasted EPIS into the test period with EPIS rate base established at an average test year level—is almost never going to

[41] Staff/1900, Stevens/28.
[42] Staff/1900, Stevens/33.

be lower than an end-of-period balance, truncated on the day before new rates take effect in the test year.

**Q. Can you elaborate on this?**

A. Yes. Staff's assumption that the AMA net plant balance into a test period must be lower than a pre-test-period, end-of-period balance is only true under Staff's faulty understanding of rate base balances and how they change over time. Below are three hypothetical scenarios created to illustrate the flaw in Staff's reasoning. Scenario 1 is an illustration of a scenario consistent with Staff's proposal—where no test year gross plant additions are included in rate base calculations, but reserves are walked forward into the test year.

**Scenario 1 – No Test Year Gross Plant Additions**

| | | No Test Year Additions | | | | |
|---|---|---|---|---|---|---|
| | | Additions | Gross Plant | Depreciation | Accum. Reserves | Net Plant |
| | December | 10,000,000 | 10,000,000 | 250,000 | (250,000) | 9,750,000 |
| Test Year | January | - | 10,000,000 | 500,000 | (750,000) | 9,250,000 |
| | February | - | 10,000,000 | 500,000 | (1,250,000) | 8,750,000 |
| | March | - | 10,000,000 | 500,000 | (1,750,000) | 8,250,000 |
| | April | - | 10,000,000 | 500,000 | (2,250,000) | 7,750,000 |
| | May | - | 10,000,000 | 500,000 | (2,750,000) | 7,250,000 |
| | June | - | 10,000,000 | 500,000 | (3,250,000) | 6,750,000 |
| | July | - | 10,000,000 | 500,000 | (3,750,000) | 6,250,000 |
| | August | - | 10,000,000 | 500,000 | (4,250,000) | 5,750,000 |
| | September | - | 10,000,000 | 500,000 | (4,750,000) | 5,250,000 |
| | October | - | 10,000,000 | 500,000 | (5,250,000) | 4,750,000 |
| | November | - | 10,000,000 | 500,000 | (5,750,000) | 4,250,000 |
| | December | - | 10,000,000 | 500,000 | (6,250,000) | 3,750,000 |
| | | | | | | |
| | | | **EOP Net Plant (Pre-Test Year)** | | **9,750,000** | |
| | | | **AMA Net Plant (Test Year)** | | **6,750,000** | |
| | | | | | | |
| | | | Depreciation Rate (Monthly) | | 5% | |

Scenario 2 is a modified scenario, where test year plant additions are considered, but gross plant investments are made at a conservative level, only sufficient to match the pace at which assets are being depreciated or "used".

**Scenario 2 – Conservative Test Year Gross Plant Additions**

| | | Conservative Test Year Additions | | | | |
|---|---|---|---|---|---|---|
| | | Additions | Gross Plant | Depreciation | Accum. Reserves | Net Plant |
| | December | 10,000,000 | 10,000,000 | 250,000 | (250,000) | 9,750,000 |
| Test Year | January | 512,821 | 10,512,821 | 512,821 | (762,821) | 9,750,000 |
| | February | 539,119 | 11,051,940 | 539,119 | (1,301,940) | 9,750,000 |
| | March | 566,766 | 11,618,706 | 566,766 | (1,868,706) | 9,750,000 |
| | April | 595,831 | 12,214,537 | 595,831 | (2,464,537) | 9,750,000 |
| | May | 626,386 | 12,840,923 | 626,386 | (3,090,923) | 9,750,000 |
| | June | 658,509 | 13,499,432 | 658,509 | (3,749,432) | 9,750,000 |
| | July | 692,279 | 14,191,711 | 692,279 | (4,441,711) | 9,750,000 |
| | August | 727,780 | 14,919,491 | 727,780 | (5,169,491) | 9,750,000 |
| | September | 765,102 | 15,684,593 | 765,102 | (5,934,593) | 9,750,000 |
| | October | 804,338 | 16,488,931 | 804,338 | (6,738,931) | 9,750,000 |
| | November | 845,586 | 17,334,517 | 845,586 | (7,584,517) | 9,750,000 |
| | December | 888,950 | 18,223,467 | 888,950 | (8,473,467) | 9,750,000 |
| | | | | | | |
| | | | **EOP Net Plant (Pre-Test Year)** | | **9,750,000** | |
| | | | **AMA Net Plant (Test Year)** | | **9,750,000** | |
| | | | | | | |
| | | | Depreciation Rate (Monthly) | | 5% | |

Finally, Scenario 3 is a more realistic scenario, where a utility's rate base is growing, and test year plant investments are made at a level that is more than sufficient to replenish depreciated, or "used", rate base.

**Scenario 3 – Realistic Test Year Gross Plant Additions**

| | | Realistic Test Year Additions | | | | |
|---|---|---|---|---|---|---|
| | | Additions | Gross Plant | Depreciation | Accum. Reserves | Net Plant |
| | December | 10,000,000 | 10,000,000 | 250,000 | (250,000) | 9,750,000 |
| Test Year | January | 539,153 | 10,539,153 | 513,479 | (763,479) | 9,775,674 |
| | February | 568,221 | 11,107,374 | 541,163 | (1,304,642) | 9,802,732 |
| | March | 598,857 | 11,706,231 | 570,340 | (1,874,982) | 9,831,249 |
| | April | 631,145 | 12,337,376 | 601,090 | (2,476,072) | 9,861,304 |
| | May | 665,173 | 13,002,549 | 633,498 | (3,109,570) | 9,892,979 |
| | June | 701,036 | 13,703,585 | 667,653 | (3,777,224) | 9,926,361 |
| | July | 738,833 | 14,442,418 | 703,650 | (4,480,874) | 9,961,544 |
| | August | 778,667 | 15,221,084 | 741,588 | (5,222,461) | 9,998,623 |
| | September | 820,649 | 16,041,733 | 781,570 | (6,004,032) | 10,037,702 |
| | October | 864,894 | 16,906,628 | 823,709 | (6,827,741) | 10,078,887 |
| | November | 911,526 | 17,818,153 | 868,120 | (7,695,860) | 10,122,293 |
| | December | 960,671 | 18,778,824 | 914,924 | (8,610,785) | 10,168,039 |
| | | | | | | |
| | | | **EOP Net Plant (Pre-Test Year)** | | **9,750,000** | |
| | | | **AMA Net Plant (Test Year)** | | **9,937,364** | |
| | | | | | | |
| | | | Depreciation Rate (Monthly) | | 5% | |
| | | | Incremental Asset Growth (Monthly) | | 5% | |

The table below summarizes the pre-test-year EOP net plant balance (akin to the Company's proposed EPIS rate base), and the test year AMA net plant balance (similar to Staff's proposal, but properly reflecting AMA calculation of both gross plant and net plant into the test year).

**TABLE 6—Summary of EPIS Rate Base Scenarios**

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| | No Additions | Conservative | Realistic |
| EOP Net Plant (Pre-Test Year) | 9,750,000 | 9,750,000 | 9,750,000 |
| AMA Net Plant (Test Year) | 6,750,000 | 9,750,000 | 9,937,364 |

As summarized in Table 6, the only scenario where an AMA net plant into the test year is lower than the EOP pre-test-year is if no capital additions are taken into account in the test year. This is not a realistic or reasonable scenario.

**Q. Why is it realistic to expect that the Company will put additional plants or assets into service through a test year?**

A. For most businesses, over a full cycle, capital expenditure should be expected to be greater than depreciation. This is because most businesses are growing and need capital to do so. While depreciation is spreading historical purchase costs over time, the replacement value of those expenditures is also typically higher due to inflation. If a business has capital expenditures that are chronically lower than depreciation over a period of time, this creates a problem where the business's asset base shrinks, and the business essentially is slowly liquidating itself. This is not the case for PacifiCorp, which has historically experienced circumstances in which capital expenditures consistently exceed depreciation. Company witness Kobliha's direct testimony explains the level of capital investments the Company expects in the near future.

Accordingly, the only scenario in which PacifiCorp's rates would be higher

under the Company's EOP approach than they would be under an AMA approach is if the AMA unrealistically ignores the capital investments to be added into gross plant balances in the test year, which Staff's proposed adjustment does. In all reasonable and realistic scenarios, the AMA test year net plant balance will always be the same, or higher, than a pre-test year EOP net EPIS balance.

**Q. What other issue does Staff's proposed adjustment fail to take into account?**

A. Because the proposed adjustment involves public utility property, the adjustment must be in compliance with the normalization rules of the Internal Revenue Code (IRC). Generally speaking, PacifiCorp is only permitted to claim accelerated depreciation on public utility property in its federal income tax return if it uses a normalization method of accounting as described in IRC Section 168(i)(9). This includes a prohibition on the use of inconsistent estimates and projections for ratemaking purposes as described in IRC Section 168(i)(10) (i.e., the consistency rules). The consistency rules prohibit any procedure or adjustment for ratemaking purposes which uses an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes, unless such estimate or projection is also used with respect to the other two such items and with respect to the rate base. Also, to the extent that a future test period is used, Treasury Regulation 1.167(l)-1(h)(6)(ii) requires the use of a proration formula for the reserve for deferred taxes. As presented by Staff, the proposed adjustment to reflect a change to the Staff-described "AMA" EPIS rate base methodology, is not a comprehensive adjustment, in part because it does not contemplate any necessary corresponding adjustment to tax balances that would ensure compliance with the normalization rules of the IRC.

**Q. Staff states that the "AMA" approach is Staff's preferred method for the rate base calculation in rate filings, but to your knowledge, has this methodology, as proposed by Staff, been required by the Commission in any utility's rate filings?**

A. No. Staff cites Commission orders from the 1970s supporting an AMA approach,[43] but those orders pre-date the adoption of ORS 757.355's used and useful requirement and did not consider a modified AMA approach that mismatches plant and depreciation as Staff proposes here. As Staff notes, Staff has recently proposed its modified AMA approach in several other utilities' rate cases, but the issue has not been litigated and resolved by the Commission in those cases. Staff testifies that Avista agreed to use Staff's AMA methodology in settlement, but I note the settlement reflects that Avista did not agree to Staff's rationale and reserved the right to address the issue in a future proceeding.[44]

**Q. Does any other utility employ a rate base methodology similar to PacifiCorp's?**

A. Yes, I understand that PGE adopted a year-end point-in-time rate base method in docket UE 283 (filed in 2013) and has used the same approach ever since.[45] Staff acknowledged PGE's use of year-end rate base in docket UE 283.[46]

[43] Staff/1900, Stevens/29.
[44] *See* Docket No. UG 461, Stipulating Parties/200, Muldoon – Schultz – Miller – Garrett – Mullins – Plummer – Ryan/ 10 (Aug. 17, 2023).
[45] *In the Matter of Portland General Electric Request for General Rate Revision,* Docket No. UE 416, PGE/1700, Batzler-Ferchland/18-20 (July 21, 2023).
[46] *In the Matter of Portland General Electric Request for General Rate Revision,* Docket No. UE 283, Staff/600, Garcia/1 (Jun. 11, 2014).

**Q. Staff suggests that PacifiCorp's EOP approach is not appropriate because the Company can time its rate cases to control regulatory lag.[47] How do you respond?**

A. I do not agree with Staff's suggestion that PacifiCorp's EOP rate base methodology does more to mitigate regulatory lag than Staff's proposed modified AMA methodology. Both the Company's and Staff's methodologies only include capital additions prior to the rate-effective date, so the regulatory lag that results from both approaches is the same. However, in response to Staff's testimony, I note that there are many considerations that ought to be taken into account when deciding on timing around rate filings. Even with filings made annually, each GRC requires a statutory procedural period where typically rates do not go into effect until almost a full year after an application for rate revision is filed. Constant rate filings to keep up with regulatory lag is also not a desirable outcome for the Company, the Commission, customers, or intervening parties needing to dedicate substantial time and effort to review each utility filing.

**Q. Staff faults PacifiCorp for failing to provide a data response quantifying the impact of Staff's adjustment and disagreed with the Company's assertion that the quantification of the impact of its EPIS rate base adjustment is overly burdensome.[48] Can you explain the Company's position on this?**

A. Staff pointed to the Company's response to OPUC Data Request 626 where the Company objected to the request as overly burdensome to complete. After reviewing Staff's testimony on the EPIS rate base issue, I believe that Staff and the Company

[47] Staff/1900, Stevens/34.
[48] Staff/1900, Stevens/34-35.

have different views about the burdensomeness of this request because Staff and the Company have a fundamental disagreement about what would constitute a properly calculated test year "AMA" rate base. I now understand that Staff's "AMA" proposal is a simplistic and incomplete view solely focused on the walk-forward of depreciation reserves into the test period. In contrast, the Company's interpretation of a properly executed test year "AMA" rate base not only would require pulling into the GRC the forecasted capital additions through the Test Period (which Staff's data request asked the Company not to do), but also would require recalculation of several other adjustments included in its direct filing that restate or pro form EPIS and related balances to properly establish a consistent test year AMA rate base across all plant and associated accumulated reserves, and deferred income tax balances that adhere to the matching principle.

For context, it takes the Company multiple months to prepare a GRC. Revising all the pertinent cost elements in this filing to reflect an AMA rate base (even one that excludes capital additions) would take time beyond what is available under the procedural schedule. The change in rate base methodology would also have an impact on some of the allocations factors and would impact many of the Company's proposed adjustments in this case.

**Q. Please summarize the Company's response to Staff's proposal regarding the use of Staff's "AMA" methodology.**

A. Staff's proposal is not a true "AMA" methodology. The effect of Staff's proposed methodology is a mix-and-match of EPIS rate base balances that is contrary to the matching principle and also raises tax normalization issues. Staff's accusation that the

Company's currently utilized EPIS rate base methodology results in the Company being overcompensated is rooted in unrealistic expectations of how much incremental investments can be expected throughout the rate effective period of the case. In fact, as illustrated by a comparison of scenarios in my testimony, if Staff's proposal were adopted, it would result in the Company being unfairly undercompensated.

The Company's annualized pre-test year EOP methodology has been consistently relied upon to set retail rates in PacifiCorp's GRCs for over a decade, since docket UE 217, and is compliant with ORS 757.355. The Company's EPIS rate base approach, as filed, represents a fair and reasonable approach that allows the Company to recover prudently incurred capital costs without suffering from excessive regulatory lag. I recommend that the Commission reject Staff's AMA proposal and find the Company's proposed pre-test-year EOP rate base for EPIS and related balances, that has been relied upon for well over a decade, be maintained.

## IV. CONCLUSION

**Q. Please summarize your reply testimony.**

A. The Company's non-NPC base rate request in this GRC has been reduced by $30.0 million to $127.6 million, primarily driven by a reduction to requested ROE from 10.3 percent to 9.65 percent. The Company accepts corrections, revisions and adjustments from Staff and AWEC including:

- Staff's proposal to reduce the projected escalation of test period medical benefits from 8 percent to 6 percent;
- Update to reflect latest OPUC fees approved in 2024;
- Partially accepted Staff's proposed incremental adjustment to M&E expenses;

- Acceptance of Staff's proposal to include customer payment fees expenses on a three-year historical average basis, and reflect a correction to the Base Period customer payment fees as provided in the Company's direct filing;
- Corrections as supported by Staff, with additional updates made to forecast fuel stock balances for specific plants;
- Incorporated specific corrections and updates proposed by Staff and AWEC on the calculation of the wildfire deferred costs amortization; and
- Accepted, in principle, the introduction of a capitalized officer incentives removal adjustment.

With exception of these accepted corrections and adjustments, the Company disagrees with all other recommended adjustments proposed by parties in this case. The Company respectfully requests the Commission approve a $127.6 million non-NPC base rate change for the 2025 Test Period in this GRC.

**Q. Does this conclude your reply testimony?**

A. Yes, it does.

Docket No. UE 433
Exhibit PAC/3301
Witness: Sherona L. Cheung

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Sherona L. Cheung**

**Revenue Requirement Summary**

**July 2024**

**PacifiCorp** **Page 1.0_R**

**OREGON**

**Normalized Results of Operations - 2020 PROTOCOL**

**Twelve Months Ending December 31, 2025**

| | (1) | (2) (3) - (1) | (3) Ref. Page 1.4_R | (4) | (5) | (6) (3) + (4) + (5) |
|---|---|---|---|---|---|---|
| | | | | **TAM** | **GRC** | |
| | NPC-Related Results | Non-NPC Related Results | Total Adjusted Results | NPC-Related Under Recovery | Requested Non-NPC Related Price Change | Total Normalized Results with Price Change |
| 1 Operating Revenues: | | | | | | |
| 2 General Business Revenues | 604,412,863 | 1,076,524,475 | 1,680,937,338 | (23,119,457) | 127,635,788 | 1,785,453,669 |
| 3 Interdepartmental | | - | - | | | - |
| 4 Special Sales | 88,412,673 | - | 88,412,673 | | | 88,412,673 |
| 5 Other Operating Revenues | | 71,672,999 | 71,672,999 | | | 71,672,999 |
| 6 Total Operating Revenues | 692,825,536 | 1,148,197,474 | 1,841,023,010 | (23,119,457) | 127,635,788 | 1,945,539,341 |
| 7 | | | | | | |
| 8 Operating Expenses: | | | | | | |
| 9 Steam Production | 188,225,095 | 88,668,797 | 276,893,892 | | | 276,893,892 |
| 10 Nuclear Production | | - | - | | | - |
| 11 Hydro Production | | 13,594,108 | 13,594,108 | | | 13,594,108 |
| 12 Other Power Supply | 517,116,600 | 30,369,149 | 547,485,749 | | | 547,485,749 |
| 13 Transmission | 51,511,038 | 19,610,833 | 71,121,871 | | | 71,121,871 |
| 14 Distribution | | 114,542,254 | 114,542,254 | | | 114,542,254 |
| 15 Customer Accounting | | 28,163,160 | 28,163,160 | | 654,012 | 28,817,171 |
| 16 Customer Service & Info | | 5,298,846 | 5,298,846 | | | 5,298,846 |
| 17 Sales | | - | - | | | - |
| 18 Administrative & General | | 61,765,305 | 61,765,305 | | | 61,765,305 |
| 19 | | | | | | |
| 20 Total O&M Expenses | 756,852,733 | 362,012,451 | 1,118,865,185 | - | 654,012 | 1,119,519,196 |
| 21 | | | | | | |
| 22 Depreciation | | 317,074,767 | 317,074,767 | | | 317,074,767 |
| 23 Amortization | | 27,809,318 | 27,809,318 | | | 27,809,318 |
| 24 Taxes Other Than Income | | 100,593,896 | 100,593,896 | | 2,969,278 | 103,563,174 |
| 25 Income Taxes - Federal | (78,555,531) | 40,106,039 | (38,449,492) | (4,634,665) | 24,860,289 | (18,223,868) |
| 26 Income Taxes - State | (2,906,835) | 9,315,392 | 6,408,557 | (1,049,623) | 5,630,167 | 10,989,101 |
| 27 Income Taxes - Def Net | | (8,550,148) | (8,550,148) | | | (8,550,148) |
| 28 Investment Tax Credit Adj. | | - | - | | | - |
| 29 Misc Revenue & Expense | | (30,006) | (30,006) | | | (30,006) |
| 30 | | | | | | |
| 31 Total Operating Expenses: | 675,390,367 | 848,331,709 | 1,523,722,077 | (5,684,288) | 34,113,747 | 1,552,151,535 |
| 32 | | | | | | |
| 33 Operating Rev For Return: | 17,435,169 | 299,865,765 | 317,300,933 | (17,435,169) | 93,522,041 | 393,387,806 |
| 34 | | | | | | |
| 35 Rate Base: | | | | | | |
| 36 Electric Plant In Service | | 10,383,366,153 | 10,383,366,153 | | | 10,383,366,153 |
| 37 Plant Held for Future Use | | - | - | | | - |
| 38 Misc Deferred Debits | | 96,395,604 | 96,395,604 | | | 96,395,604 |
| 39 Elec Plant Acq Adj | | 703,248 | 703,248 | | | 703,248 |
| 40 Pension | | - | - | | | - |
| 41 Prepayments | | 16,838,184 | 16,838,184 | | | 16,838,184 |
| 42 Fuel Stock | | 43,544,178 | 43,544,178 | | | 43,544,178 |
| 43 Material & Supplies | | 129,822,071 | 129,822,071 | | | 129,822,071 |
| 44 Working Capital | | 48,204,849 | 48,204,849 | | | 48,204,849 |
| 45 Weatherization Loans | | - | - | | | - |
| 46 Misc Rate Base | | (98,566) | (98,566) | | | (98,566) |
| 47 | | | | | | |
| 48 Total Electric Plant: | - | 10,718,775,721 | 10,718,775,721 | | | 10,718,775,721 |
| 49 | | | | | | |
| 50 Rate Base Deductions: | | | | | | |
| 51 Accum Prov For Deprec | | (4,043,129,802) | (4,043,129,802) | | | (4,043,129,802) |
| 52 Accum Prov For Amort | | (229,765,382) | (229,765,382) | | | (229,765,382) |
| 53 Accum Def Income Tax | | (696,410,395) | (696,410,395) | | | (696,410,395) |
| 54 Unamortized ITC | | (40,918) | (40,918) | | | (40,918) |
| 55 Customer Adv For Const | | (46,658,522) | (46,658,522) | | | (46,658,522) |
| 56 Customer Service Deposits | | - | - | | | - |
| 57 Misc Rate Base Deductions | | (433,111,498) | (433,111,498) | | | (433,111,498) |
| 58 | | | | | | |
| 59 Total Rate Base Deductions | - | (5,449,116,517) | (5,449,116,517) | | | (5,449,116,517) |
| 60 | | | | | | |
| 61 Total Rate Base: | - | 5,269,659,203 | 5,269,659,203 | | | 5,269,659,203 |
| 62 | | | | | | |
| 63 Return on Rate Base | | | 6.021% | | | 7.465% |
| 64 | | | | | | |
| 65 Return on Equity | | | 6.762% | | | 9.650% |

**PacifiCorp**
**OREGON**
**Normalized Results of Operations - 2020 PROTOCOL**
**Twelve Months Ending December 31, 2025**

## GENERAL RATE CASE RESULTS

| | | (1) | (2) | (3) (1) + (2) |
|---|---|---|---|---|
| | | Total Adjusted Results | **GRC** Price Change | Total Normalized Results with Price Change |
| 1 | Operating Revenues: | | | |
| 2 | General Business Revenues | 1,076,524,475 | 127,635,788 | 1,204,160,262 |
| 3 | Interdepartmental | - | | - |
| 4 | Special Sales | - | | - |
| 5 | Other Operating Revenues | 71,672,999 | | 71,672,999 |
| 6 | Total Operating Revenues | 1,148,197,474 | 127,635,788 | 1,275,833,262 |
| 7 | | | | |
| 8 | Operating Expenses: | | | |
| 9 | Steam Production | 88,668,797 | | 88,668,797 |
| 10 | Nuclear Production | - | | - |
| 11 | Hydro Production | 13,594,108 | | 13,594,108 |
| 12 | Other Power Supply | 30,369,149 | | 30,369,149 |
| 13 | Transmission | 19,610,833 | | 19,610,833 |
| 14 | Distribution | 114,542,254 | | 114,542,254 |
| 15 | Customer Accounting | 28,163,160 | 654,012 | 28,817,171 |
| 16 | Customer Service & Info | 5,298,846 | | 5,298,846 |
| 17 | Sales | - | | - |
| 18 | Administrative & General | 61,765,305 | | 61,765,305 |
| 19 | | | | |
| 20 | Total O&M Expenses | 362,012,451 | 654,012 | 362,666,463 |
| 21 | | | | |
| 22 | Depreciation | 317,074,767 | | 317,074,767 |
| 23 | Amortization | 27,809,318 | | 27,809,318 |
| 24 | Taxes Other Than Income | 100,593,896 | 2,969,278 | 103,563,174 |
| 25 | Income Taxes - Federal | 40,106,039 | 24,860,289 | 64,966,329 |
| 26 | Income Taxes - State | 9,315,392 | 5,630,167 | 14,945,559 |
| 27 | Income Taxes - Def Net | (8,550,148) | | (8,550,148) |
| 28 | Investment Tax Credit Adj. | - | | - |
| 29 | Misc Revenue & Expense | (30,006) | | (30,006) |
| 30 | | | | |
| 31 | Total Operating Expenses: | 848,331,709 | 34,113,747 | 882,445,456 |
| 32 | | | | |
| 33 | Operating Rev For Return: | 299,865,765 | 93,522,041 | 393,387,806 |
| 34 | | | | |
| 35 | Rate Base: | | | |
| 36 | Electric Plant In Service | 10,383,366,153 | | 10,383,366,153 |
| 37 | Plant Held for Future Use | - | | - |
| 38 | Misc Deferred Debits | 96,395,604 | | 96,395,604 |
| 39 | Elec Plant Acq Adj | 703,248 | | 703,248 |
| 40 | Pension | - | | - |
| 41 | Prepayments | 16,838,184 | | 16,838,184 |
| 42 | Fuel Stock | 43,544,178 | | 43,544,178 |
| 43 | Material & Supplies | 129,822,071 | | 129,822,071 |
| 44 | Working Capital | 48,204,849 | | 48,204,849 |
| 45 | Weatherization Loans | - | | - |
| 46 | Misc Rate Base | (98,566) | | (98,566) |
| 47 | | | | |
| 48 | Total Electric Plant: | 10,718,775,721 | | 10,718,775,721 |
| 49 | | | | |
| 50 | Rate Base Deductions: | | | |
| 51 | Accum Prov For Deprec | (4,043,129,802) | | (4,043,129,802) |
| 52 | Accum Prov For Amort | (229,765,382) | | (229,765,382) |
| 53 | Accum Def Income Tax | (696,410,395) | | (696,410,395) |
| 54 | Unamortized ITC | (40,918) | | (40,918) |
| 55 | Customer Adv For Const | (46,658,522) | | (46,658,522) |
| 56 | Customer Service Deposits | - | | - |
| 57 | Misc Rate Base Deductions | (433,111,498) | | (433,111,498) |
| 58 | | | | |
| 59 | Total Rate Base Deductions | (5,449,116,517) | | (5,449,116,517) |
| 60 | | | | |
| 61 | Total Rate Base: | 5,269,659,203 | | 5,269,659,203 |
| 62 | | | | |
| 63 | Return on Rate Base | 5.690% | | 7.465% |
| 64 | | | | |
| 65 | Return on Equity | 6.101% | | 9.650% |
| 66 | | | | |
| 67 | TAX CALCULATION: | | | |
| 68 | Operating Revenue | 340,737,048 | 124,012,498 | 464,749,546 |
| 69 | Other Deductions | | | |
| 70 | Interest (AFUDC) | (65,590,851) | - | (65,590,851) |
| 71 | Interest | 139,091,179 | - | 139,091,179 |
| 72 | Schedule "M" Additions | 431,417,541 | - | 431,417,541 |
| 73 | Schedule "M" Deductions | 498,295,283 | - | 498,295,283 |
| 74 | Income Before Tax | 200,358,978 | 124,012,498 | 324,371,476 |
| 75 | | | | |
| 76 | State Income Taxes | 9,315,392 | 5,630,167 | 14,945,559 |
| 77 | Taxable Income | 191,043,587 | 118,382,331 | 309,425,917 |
| 78 | | | | |
| 79 | Federal Income Taxes + Other | 40,106,039 | 24,860,289 | 64,966,329 |

**PacifiCorp**
**OREGON**
**Normalized Results of Operations - 2020 PROTOCOL**
**Twelve Months Ending December 31, 2025**

## TRANSITION ADJUSTMENT MECHANISM RESULTS

| | | (1) | (2) | (3) (1) + (2) |
|---|---|---|---|---|
| | | Total Adjusted Results | **TAM** Price Change | Total Normalized Results with Price Change |
| 1 | Operating Revenues: | | | |
| 2 | General Business Revenues | 604,412,863 | (23,119,457) | 581,293,406 |
| 3 | Interdepartmental | - | | - |
| 4 | Special Sales | 88,412,673 | | 88,412,673 |
| 5 | Other Operating Revenues | - | | - |
| 6 | Total Operating Revenues | 692,825,536 | (23,119,457) | 669,706,079 |
| 7 | | | | |
| 8 | Operating Expenses: | | | |
| 9 | Steam Production | 188,225,095 | | 188,225,095 |
| 10 | Nuclear Production | - | | - |
| 11 | Hydro Production | - | | - |
| 12 | Other Power Supply | 517,116,600 | | 517,116,600 |
| 13 | Transmission | 51,511,038 | | 51,511,038 |
| 14 | Distribution | - | | - |
| 15 | Customer Accounting | - | - | - |
| 16 | Customer Service & Info | - | | - |
| 17 | Sales | - | | - |
| 18 | Administrative & General | - | | - |
| 19 | | | | |
| 20 | Total O&M Expenses | 756,852,733 | - | 756,852,733 |
| 21 | | | | |
| 22 | Depreciation | - | | - |
| 23 | Amortization | - | | - |
| 24 | Taxes Other Than Income | - | - | - |
| 25 | Income Taxes - Federal | (78,555,531) | (4,634,665) | (83,190,197) |
| 26 | Income Taxes - State | (2,906,835) | (1,049,623) | (3,956,458) |
| 27 | Income Taxes - Def Net | - | | - |
| 28 | Investment Tax Credit Adj. | - | | - |
| 29 | Misc Revenue & Expense | - | | - |
| 30 | | | | |
| 31 | Total Operating Expenses: | 675,390,367 | (5,684,288) | 669,706,079 |
| 32 | | | | |
| 33 | Operating Rev For Return: | 17,435,169 | (17,435,169) | - |
| 34 | | | | |
| 35 | Rate Base: | | | |
| 36 | Electric Plant In Service | - | | - |
| 37 | Plant Held for Future Use | - | | - |
| 38 | Misc Deferred Debits | - | | - |
| 39 | Elec Plant Acq Adj | - | | - |
| 40 | Pension | - | | - |
| 41 | Prepayments | - | | - |
| 42 | Fuel Stock | - | | - |
| 43 | Material & Supplies | - | | - |
| 44 | Working Capital | - | | - |
| 45 | Weatherization Loans | - | | - |
| 46 | Misc Rate Base | - | | - |
| 47 | | | | |
| 48 | Total Electric Plant: | - | | - |
| 49 | | | | |
| 50 | Rate Base Deductions: | | | |
| 51 | Accum Prov For Deprec | - | | - |
| 52 | Accum Prov For Amort | - | | - |
| 53 | Accum Def Income Tax | - | | - |
| 54 | Unamortized ITC | - | | - |
| 55 | Customer Adv For Const | - | | - |
| 56 | Customer Service Deposits | - | | - |
| 57 | Misc Rate Base Deductions | - | | - |
| 58 | | | | |
| 59 | Total Rate Base Deductions | - | | - |
| 60 | | | | |
| 61 | Total Rate Base: | - | | - |
| 62 | | | | |
| 63 | Return on Rate Base | N/A | | N/A |
| 64 | | | | |
| 65 | Return on Equity | N/A | | N/A |
| 66 | | | | |
| 67 | TAX CALCULATION: | | | |
| 68 | Operating Revenue | (64,027,198) | (23,119,457) | (87,146,655) |
| 69 | Other Deductions | | | |
| 70 | Interest (AFUDC) | - | - | - |
| 71 | Interest | - | - | - |
| 72 | Schedule "M" Additions | - | - | - |
| 73 | Schedule "M" Deductions | - | - | - |
| 74 | Income Before Tax | (64,027,198) | (23,119,457) | (87,146,655) |
| 75 | | | | |
| 76 | State Income Taxes | (2,906,835) | (1,049,623) | (3,956,458) |
| 77 | Taxable Income | (61,120,363) | (22,069,834) | (83,190,197) |
| 78 | | | | |
| 79 | Federal Income Taxes + Other | (78,555,531) | (4,634,665) | (83,190,197) |

**PacifiCorp**
**OREGON**
**Normalized Results of Operations - 2020 PROTOCOL**
**Twelve Months Ending December 31, 2025**

| | | (1) Total Adjusted Results | (2) Price Change | (3) Results with Price Change |
|---|---|---|---|---|
| 1 | Operating Revenues: | | | |
| 2 | General Business Revenues | 1,680,937,338 | 104,516,331 | 1,785,453,669 |
| 3 | Interdepartmental | - | | |
| 4 | Special Sales | 88,412,673 | | |
| 5 | Other Operating Revenues | 71,672,999 | | |
| 6 | Total Operating Revenues | 1,841,023,010 | | |
| 7 | | | | |
| 8 | Operating Expenses: | | | |
| 9 | Steam Production | 276,893,892 | | |
| 10 | Nuclear Production | - | | |
| 11 | Hydro Production | 13,594,108 | | |
| 12 | Other Power Supply | 547,485,749 | | |
| 13 | Transmission | 71,121,871 | | |
| 14 | Distribution | 114,542,254 | | |
| 15 | Customer Accounting | 28,163,160 | 654,012 | 28,817,171 |
| 16 | Customer Service & Info | 5,298,846 | | |
| 17 | Sales | - | | |
| 18 | Administrative & General | 61,765,305 | | |
| 19 | | | | |
| 20 | Total O&M Expenses | 1,118,865,185 | | |
| 21 | | | | |
| 22 | Depreciation | 317,074,767 | | |
| 23 | Amortization | 27,809,318 | | |
| 24 | Taxes Other Than Income | 100,593,896 | 2,969,278 | 103,563,174 |
| 25 | Income Taxes - Federal | (38,449,492) | 20,225,624 | (18,223,868) |
| 26 | Income Taxes - State | 6,408,557 | 4,580,544 | 10,989,101 |
| 27 | Income Taxes - Def Net | (8,550,148) | | |
| 28 | Investment Tax Credit Adj. | - | | |
| 29 | Misc Revenue & Expense | (30,006) | | |
| 30 | | | | |
| 31 | Total Operating Expenses: | 1,523,722,077 | 28,429,458 | 1,552,151,535 |
| 32 | | | | |
| 33 | Operating Rev For Return: | 317,300,933 | 76,086,873 | 393,387,806 |
| 34 | | | | |
| 35 | Rate Base: | | | |
| 36 | Electric Plant In Service | 10,383,366,153 | | |
| 37 | Plant Held for Future Use | - | | |
| 38 | Misc Deferred Debits | 96,395,604 | | |
| 39 | Elec Plant Acq Adj | 703,248 | | |
| 40 | Pensions | - | | |
| 41 | Prepayments | 16,838,184 | | |
| 42 | Fuel Stock | 43,544,178 | | |
| 43 | Material & Supplies | 129,822,071 | | |
| 44 | Working Capital | 48,204,849 | | |
| 45 | Weatherization Loans | - | | |
| 46 | Misc Rate Base | (98,566) | | |
| 47 | | | | |
| 48 | Total Electric Plant: | 10,718,775,721 | - | 10,718,775,721 |
| 49 | | | | |
| 50 | Rate Base Deductions: | | | |
| 51 | Accum Prov For Deprec | (4,043,129,802) | | |
| 52 | Accum Prov For Amort | (229,765,382) | | |
| 53 | Accum Def Income Tax | (696,410,395) | | |
| 54 | Unamortized ITC | (40,918) | | |
| 55 | Customer Adv For Const | (46,658,522) | | |
| 56 | Customer Service Deposits | - | | |
| 57 | Misc Rate Base Deductions | (433,111,498) | | |
| 58 | | | | |
| 59 | Total Rate Base Deductions | (5,449,116,517) | - | (5,449,116,517) |
| 60 | | | | |
| 61 | Total Rate Base: | 5,269,659,203 | - | 5,269,659,203 |
| 62 | | | | |
| 63 | Return on Rate Base | 6.021% | | 7.465% |
| 64 | | | | |
| 65 | Return on Equity | 6.762% | | 9.650% |
| 66 | | | | |
| 67 | TAX CALCULATION: | | | |
| 68 | Operating Revenue | 276,709,850 | 100,893,041 | 377,602,891 |
| 69 | Other Deductions | | | |
| 70 | Interest (AFUDC) | (65,590,851) | - | (65,590,851) |
| 71 | Interest | 139,091,179 | - | 139,091,179 |
| 72 | Schedule "M" Additions | 431,417,541 | - | 431,417,541 |
| 73 | Schedule "M" Deductions | 498,295,283 | - | 498,295,283 |
| 74 | Income Before Tax | 136,331,781 | 100,893,041 | 237,224,822 |
| 75 | | | | |
| 76 | State Income Taxes | 6,408,557 | 4,580,544 | 10,989,101 |
| 77 | Taxable Income | 129,923,224 | 96,312,497 | 226,235,721 |
| 78 | | | | |
| 79 | Federal Income Taxes + Other | (38,449,492) | 20,225,624 | (18,223,868) |

**PacifiCorp**
**Oregon General Rate Case**
**Adjustment Summary**
**Twelve Months Ending December 31, 2025**

| | Exhibit PAC/3302 | | Exhibit PAC/3302 | | | |
|---|---|---|---|---|---|---|
| | | | Tab 3 | Tab 4 | Tab 5 | Tab 6 |
| | TOTAL COMPANY UNADJUSTED RESULTS JUNE 2023 | OREGON ALLOCATED UNADJUSTED RESULTS JUNE 2023 | Revenue Adjustments | O&M Adjustments | Net Power Cost Adjustments | Depreciation & Amortization Adjustments |
| 1 Operating Revenues: | | | | | | |
| 2 General Business Revenues | 5,314,367,832 | 1,399,023,529 | 280,144,493 | 1,769,316 | - | - |
| 3 Interdepartmental | - | - | - | - | - | - |
| 4 Special Sales | 276,874,873 | 70,586,388 | - | - | 17,826,285 | - |
| 5 Other Operating Revenues | 272,845,382 | 74,297,451 | 1,450,937 | - | - | - |
| 6 Total Operating Revenues | 5,864,088,087 | 1,543,907,367 | 281,595,430 | 1,769,316 | 17,826,285 | - |
| 7 | | | | | | |
| 8 Operating Expenses: | | | | | | |
| 9 Steam Production | 929,501,268 | 246,336,079 | - | 283,685 | 26,827,464 | 3,818,882 |
| 10 Nuclear Production | - | - | - | - | - | - |
| 11 Hydro Production | 42,657,730 | 11,468,171 | - | 2,689,386 | - | - |
| 12 Other Power Supply | 1,454,847,175 | 520,565,938 | - | 2,644,070 | 23,376,731 | - |
| 13 Transmission | 247,176,958 | 66,310,208 | - | (1,954,519) | 6,766,182 | - |
| 14 Distribution | 282,601,391 | 104,588,448 | - | 9,124,295 | - | - |
| 15 Customer Accounting | 80,792,201 | 23,991,155 | - | 4,172,005 | - | - |
| 16 Customer Service & Info | 158,979,871 | 4,916,333 | - | 382,513 | - | - |
| 17 Sales | - | - | - | - | - | - |
| 18 Administrative & General | 630,431,721 | 172,101,036 | - | (110,810,560) | - | - |
| 19 | | | | | | |
| 20 Total O&M Expenses | 3,826,988,315 | 1,150,277,368 | - | (93,469,126) | 56,970,377 | 3,818,882 |
| 21 | | | | | | |
| 22 Depreciation | 993,452,379 | 271,108,388 | - | - | - | 40,255,866 |
| 23 Amortization | 76,333,322 | 15,984,719 | - | - | - | (2,716,107) |
| 24 Taxes Other Than Income | 188,692,373 | 74,630,102 | - | 6,690,549 | - | - |
| 25 Income Taxes - Federal | (253,281,170) | (73,709,627) | 56,439,197 | 18,651,924 | (7,854,659) | (3,029,860) |
| 26 Income Taxes - State | (2,828,341) | (1,608,219) | 12,781,916 | 4,224,145 | (1,778,863) | (686,179) |
| 27 Income Taxes - Def Net | 55,172,095 | (9,956,034) | - | (1,865,118) | - | (938,932) |
| 28 Investment Tax Credit Adj. | (910,300) | - | - | - | - | - |
| 29 Misc Revenue & Expense | (396,311) | (50,000) | - | 19,995 | - | - |
| 30 | | | | | | |
| 31 Total Operating Expenses: | 4,883,222,363 | 1,426,676,697 | 69,221,112 | (65,747,631) | 47,336,855 | 36,703,670 |
| 32 | | | | | | |
| 33 Operating Rev For Return: | 980,865,723 | 117,230,670 | 212,374,318 | 67,516,947 | (29,510,570) | (36,703,670) |
| 34 | | | | | | |
| 35 Rate Base: | | | | | | |
| 36 Electric Plant In Service | 32,886,279,146 | 9,145,444,083 | - | - | - | - |
| 37 Plant Held for Future Use | 14,174,575 | 7,461,409 | - | - | - | - |
| 38 Misc Deferred Debits | 1,636,633,742 | 182,518,703 | - | - | - | - |
| 39 Elec Plant Acq Adj | 11,954,169 | 723,506 | - | - | - | - |
| 40 Pensions | 104,951,393 | 28,783,408 | - | - | - | - |
| 41 Prepayments | 96,171,480 | 16,838,184 | - | - | - | - |
| 42 Fuel Stock | 137,605,040 | 36,243,955 | - | - | - | - |
| 43 Material & Supplies | 407,130,439 | 129,822,071 | - | - | - | - |
| 44 Working Capital | 127,419,617 | 47,141,218 | 2,100,248 | (1,938,875) | 1,436,254 | 3,120 |
| 45 Weatherization Loans | 224,530,257 | - | - | - | - | - |
| 46 Misc Rate Base | - | - | - | - | - | - |
| 47 | | | | | | |
| 48 Total Electric Plant: | 35,646,849,859 | 9,594,976,538 | 2,100,248 | (1,938,875) | 1,436,254 | 3,120 |
| 49 | | | | | | |
| 50 Rate Base Deductions: | | | | | | |
| 51 Accum Prov For Deprec | (11,020,394,328) | (3,223,614,207) | - | - | - | (817,609,078) |
| 52 Accum Prov For Amort | (731,617,791) | (207,213,607) | - | - | - | (25,921,413) |
| 53 Accum Def Income Tax | (2,927,745,908) | (674,015,477) | - | (38,564,469) | - | 1,988,755 |
| 54 Unamortized ITC | (2,260,839) | (45,635) | - | - | - | - |
| 55 Customer Adv For Const | (193,419,991) | (73,982,464) | - | - | - | - |
| 56 Customer Service Deposits | - | - | - | - | - | - |
| 57 Misc Rate Base Deductions | (2,624,994,265) | (610,776,749) | - | 156,851,573 | - | (8,088,788) |
| 58 | | | | | | |
| 59 Total Rate Base Deductions | (17,500,433,122) | (4,789,648,140) | - | 118,287,105 | - | (849,630,523) |
| 60 | | | | | | |
| 61 Total Rate Base: | 18,146,416,737 | 4,805,328,398 | 2,100,248 | 116,348,229 | 1,436,254 | (849,627,403) |
| 62 | | | | | | |
| 63 Return on Rate Base | | 2.440% | 4.417% | 1.209% | -0.602% | 0.655% |
| 64 | | | | | | |
| 65 Return on Equity | | -0.401% | 8.833% | 2.418% | -1.203% | 1.311% |
| 66 | | | | | | |
| 67 TAX CALCULATION: | | | | | | |
| 68 Operating Revenue | | 31,956,790 | 281,595,430 | 88,527,898 | (39,144,093) | (41,358,641) |
| 69 Other Deductions | | | | | | |
| 70 Interest (AFUDC) | | (27,057,087) | - | - | - | - |
| 71 Interest | | 126,835,298 | 55,435 | 3,070,979 | 37,910 | (22,425,677) |
| 72 Schedule "M" Additions | | 349,040,084 | - | 7,585,912 | - | 3,818,882 |
| 73 Schedule "M" Deductions | | 382,368,862 | - | - | - | - |
| 74 Income Before Tax | | (101,150,200) | 281,539,995 | 93,042,831 | (39,182,002) | (15,114,082) |
| 75 | | | | | | |
| 76 State Income Taxes | | (1,608,219) | 12,781,916 | 4,224,145 | (1,778,863) | (686,179) |
| 77 Taxable Income | | (99,541,981) | 268,758,079 | 88,818,686 | (37,403,139) | (14,427,902) |
| 78 | | | | | | |
| 79 Federal Income Taxes + Other | | (73,709,627) | 56,439,197 | 18,651,924 | (7,854,659) | (3,029,860) |
| APPROXIMATE PRICE CHANGE | | 331,685,456 | (291,517,421) | (80,765,766) | 40,684,319 | (36,706,897) |

**PacifiCorp**
**Oregon General Rate Case**
**Adjustment Summary**
**Twelve Months Ending December 31, 2025**

Exhibit PAC/3302

| | Tab 7 | Tab 8 | REPLY | OR Allocated |
|---|---|---|---|---|
| | Tax Adjustments | Rate Base Adjustments | Reply Adjustments NEW | Results of Operations December 2025 |
| 1 Operating Revenues: | | | | |
| 2 General Business Revenues | - | - | - | 1,680,937,338 |
| 3 Interdepartmental | - | - | - | - |
| 4 Special Sales | - | - | - | 88,412,673 |
| 5 Other Operating Revenues | - | (4,075,388) | - | 71,672,999 |
| 6 Total Operating Revenues | - | (4,075,388) | - | 1,841,023,010 |
| 7 | | | | |
| 8 Operating Expenses: | | | | |
| 9 Steam Production | - | (372,219) | - | 276,893,892 |
| 10 Nuclear Production | - | - | - | - |
| 11 Hydro Production | - | (563,449) | - | 13,594,108 |
| 12 Other Power Supply | - | 899,010 | - | 547,485,749 |
| 13 Transmission | - | - | - | 71,121,871 |
| 14 Distribution | - | 829,511 | - | 114,542,254 |
| 15 Customer Accounting | - | - | - | 28,163,160 |
| 16 Customer Service & Info | - | - | - | 5,298,846 |
| 17 Sales | - | - | - | - |
| 18 Administrative & General | - | 474,830 | - | 61,765,305 |
| 19 | | | | |
| 20 Total O&M Expenses | - | 1,267,683 | - | 1,118,865,185 |
| 21 | | | | |
| 22 Depreciation | - | 5,713,429 | (2,916) | 317,074,767 |
| 23 Amortization | - | 17,633,929 | (3,093,223) | 27,809,318 |
| 24 Taxes Other Than Income | 19,273,245 | - | - | 100,593,896 |
| 25 Income Taxes - Federal | (29,056,360) | (3,843,113) | 3,953,006 | (38,449,492) |
| 26 Income Taxes - State | (6,549,130) | (870,359) | 895,246 | 6,408,557 |
| 27 Income Taxes - Def Net | 18,420,095 | (10,331,715) | (3,878,445) | (8,550,148) |
| 28 Investment Tax Credit Adj. | - | - | - | - |
| 29 Misc Revenue & Expense | - | - | - | (30,006) |
| 30 | | | | |
| 31 Total Operating Expenses: | 2,087,850 | 9,569,854 | (2,126,331) | 1,523,722,077 |
| 32 | | | | |
| 33 Operating Rev For Return: | (2,087,850) | (13,645,242) | 2,126,331 | 317,300,933 |
| 34 | | | | |
| 35 Rate Base: | | | | |
| 36 Electric Plant In Service | - | 1,280,362,797 | (42,440,727) | 10,383,366,153 |
| 37 Plant Held for Future Use | - | (7,461,409) | - | - |
| 38 Misc Deferred Debits | - | (86,123,100) | - | 96,395,604 |
| 39 Elec Plant Acq Adj | - | (20,258) | - | 703,248 |
| 40 Pensions | - | (28,783,408) | - | - |
| 41 Prepayments | - | - | - | 16,838,184 |
| 42 Fuel Stock | - | 7,300,223 | - | 43,544,178 |
| 43 Material & Supplies | - | - | - | 129,822,071 |
| 44 Working Capital | (495,539) | (188,679) | 147,102 | 48,204,849 |
| 45 Weatherization Loans | - | - | - | - |
| 46 Misc Rate Base | - | - | (98,566) | (98,566) |
| 47 | | | | |
| 48 Total Electric Plant: | (495,539) | 1,165,086,166 | (42,392,192) | 10,718,775,721 |
| 49 | | | | |
| 50 Rate Base Deductions: | | | | |
| 51 Accum Prov For Deprec | - | (1,906,517) | - | (4,043,129,802) |
| 52 Accum Prov For Amort | - | 276,415 | 3,093,223 | (229,765,382) |
| 53 Accum Def Income Tax | (34,395,710) | 41,418,474 | 7,158,032 | (696,410,395) |
| 54 Unamortized ITC | 4,716 | - | - | (40,918) |
| 55 Customer Adv For Const | - | 27,323,942 | - | (46,658,522) |
| 56 Customer Service Deposits | - | - | - | - |
| 57 Misc Rate Base Deductions | 29,710,341 | (807,875) | - | (433,111,498) |
| 58 | | | | |
| 59 Total Rate Base Deductions | (4,680,653) | 66,304,439 | 10,251,255 | (5,449,116,517) |
| 60 | | | | |
| 61 Total Rate Base: | (5,176,192) | 1,231,390,605 | (32,140,936) | 5,269,659,203 |
| 62 | | | | |
| 63 Return on Rate Base | -0.041% | -2.134% | 0.077% | 6.021% |
| 64 | | | | |
| 65 Return on Equity | -0.082% | -4.267% | 0.153% | 6.762% |
| 66 | | | | |
| 67 TAX CALCULATION: | | | | |
| 68 Operating Revenue | (19,273,245) | (28,690,429) | 3,096,139 | 276,709,850 |
| 69 Other Deductions | | | | |
| 70 Interest (AFUDC) | (38,533,764) | - | - | (65,590,851) |
| 71 Interest | (136,624) | 32,502,210 | (848,351) | 139,091,179 |
| 72 Schedule "M" Additions | 40,628,028 | 33,437,860 | (3,093,223) | 431,417,541 |
| 73 Schedule "M" Deductions | 143,378,120 | (8,583,880) | (18,867,819) | 498,295,283 |
| 74 Income Before Tax | (83,352,948) | (19,170,899) | 19,719,086 | 136,331,781 |
| 75 | | | | |
| 76 State Income Taxes | (6,549,130) | (870,359) | 895,246 | 6,408,557 |
| 77 Taxable Income | (76,803,818) | (18,300,540) | 18,823,839 | 129,923,224 |
| 78 | | | | |
| 79 Federal Income Taxes + Other | (29,056,360) | (3,843,113) | 3,953,006 | (38,449,492) |
| APPROXIMATE PRICE CHANGE | 2,337,174 | 145,016,168 | (6,216,703) | 104,516,331 |

Docket No. UE 433
Exhibit PAC/3302
Witness: Sherona L. Cheung

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Sherona L. Cheung**

**Oregon Results of Operations – December 2025**

**July 2024**

# Tab 1 - Results

**PacifiCorp**
**OREGON**
**Normalized Results of Operations - 2020 PROTOCOL**
**Twelve Months Ending December 31, 2025**



| | | | |
|---|---|---|---|
| (1) | Test Period 2020 Protocol Revenue Requirement | 1,785,453,669 | Page 1.1_R |
| (2) | Normalized General Business Revenues | 1,680,937,338 | Page 1.1_R |
| (3) | 2020 Protocol Price Change | **104,516,331** | Page 1.4_R |

**PacifiCorp** **Page 1.1_R**
**OREGON**
**Normalized Results of Operations - 2020 PROTOCOL**
**Twelve Months Ending December 31, 2025**

| | (1) | (2) (3) - (1) | (3) Ref. Page 1.4_R | (4) TAM | (5) GRC | (6) (3) + (4) + (5) |
|---|---|---|---|---|---|---|
| | NPC-Related Results | Non-NPC Related Results | Total Adjusted Results | NPC-Related Under Recovery | Requested Non-NPC Related Price Change | Total Normalized Results with Price Change |
| 1 Operating Revenues: | | | | | | |
| 2 General Business Revenues | 604,412,863 | 1,076,524,475 | 1,680,937,338 | (23,119,457) | 127,635,788 | 1,785,453,669 |
| 3 Interdepartmental | | - | - | | | - |
| 4 Special Sales | 88,412,673 | - | 88,412,673 | | | 88,412,673 |
| 5 Other Operating Revenues | | 71,672,999 | 71,672,999 | | | 71,672,999 |
| 6 Total Operating Revenues | 692,825,536 | 1,148,197,474 | 1,841,023,010 | (23,119,457) | 127,635,788 | 1,945,539,341 |
| 7 | | | | | | |
| 8 Operating Expenses: | | | | | | |
| 9 Steam Production | 188,225,095 | 88,668,797 | 276,893,892 | | | 276,893,892 |
| 10 Nuclear Production | | - | - | | | - |
| 11 Hydro Production | | 13,594,108 | 13,594,108 | | | 13,594,108 |
| 12 Other Power Supply | 517,116,600 | 30,369,149 | 547,485,749 | | | 547,485,749 |
| 13 Transmission | 51,511,038 | 19,610,833 | 71,121,871 | | | 71,121,871 |
| 14 Distribution | | 114,542,254 | 114,542,254 | | | 114,542,254 |
| 15 Customer Accounting | | 28,163,160 | 28,163,160 | | 654,012 | 28,817,171 |
| 16 Customer Service & Info | | 5,298,846 | 5,298,846 | | | 5,298,846 |
| 17 Sales | | - | - | | | - |
| 18 Administrative & General | | 61,765,305 | 61,765,305 | | | 61,765,305 |
| 19 | | | | | | |
| 20 Total O&M Expenses | 756,852,733 | 362,012,451 | 1,118,865,185 | - | 654,012 | 1,119,519,196 |
| 21 | | | | | | |
| 22 Depreciation | | 317,074,767 | 317,074,767 | | | 317,074,767 |
| 23 Amortization | | 27,809,318 | 27,809,318 | | | 27,809,318 |
| 24 Taxes Other Than Income | | 100,593,896 | 100,593,896 | | 2,969,278 | 103,563,174 |
| 25 Income Taxes - Federal | (78,555,531) | 40,106,039 | (38,449,492) | (4,634,665) | 24,860,289 | (18,223,868) |
| 26 Income Taxes - State | (2,906,835) | 9,315,392 | 6,408,557 | (1,049,623) | 5,630,167 | 10,989,101 |
| 27 Income Taxes - Def Net | | (8,550,148) | (8,550,148) | | | (8,550,148) |
| 28 Investment Tax Credit Adj. | | - | - | | | - |
| 29 Misc Revenue & Expense | | (30,006) | (30,006) | | | (30,006) |
| 30 | | | | | | |
| 31 Total Operating Expenses: | 675,390,367 | 848,331,709 | 1,523,722,077 | (5,684,288) | 34,113,747 | 1,552,151,535 |
| 32 | | | | | | |
| 33 Operating Rev For Return: | 17,435,169 | 299,865,765 | 317,300,933 | (17,435,169) | 93,522,041 | 393,387,806 |
| 34 | | | | | | |
| 35 Rate Base: | | | | | | |
| 36 Electric Plant In Service | | 10,383,366,153 | 10,383,366,153 | | | 10,383,366,153 |
| 37 Plant Held for Future Use | | - | - | | | - |
| 38 Misc Deferred Debits | | 96,395,604 | 96,395,604 | | | 96,395,604 |
| 39 Elec Plant Acq Adj | | 703,248 | 703,248 | | | 703,248 |
| 40 Pension | | - | - | | | - |
| 41 Prepayments | | 16,838,184 | 16,838,184 | | | 16,838,184 |
| 42 Fuel Stock | | 43,544,178 | 43,544,178 | | | 43,544,178 |
| 43 Material & Supplies | | 129,822,071 | 129,822,071 | | | 129,822,071 |
| 44 Working Capital | | 48,204,849 | 48,204,849 | | | 48,204,849 |
| 45 Weatherization Loans | | - | - | | | - |
| 46 Misc Rate Base | | (98,566) | (98,566) | | | (98,566) |
| 47 | | | | | | |
| 48 Total Electric Plant: | - | 10,718,775,721 | 10,718,775,721 | | | 10,718,775,721 |
| 49 | | | | | | |
| 50 Rate Base Deductions: | | | | | | |
| 51 Accum Prov For Deprec | | (4,043,129,802) | (4,043,129,802) | | | (4,043,129,802) |
| 52 Accum Prov For Amort | | (229,765,382) | (229,765,382) | | | (229,765,382) |
| 53 Accum Def Income Tax | | (696,410,395) | (696,410,395) | | | (696,410,395) |
| 54 Unamortized ITC | | (40,918) | (40,918) | | | (40,918) |
| 55 Customer Adv For Const | | (46,658,522) | (46,658,522) | | | (46,658,522) |
| 56 Customer Service Deposits | | - | - | | | - |
| 57 Misc Rate Base Deductions | | (433,111,498) | (433,111,498) | | | (433,111,498) |
| 58 | | | | | | |
| 59 Total Rate Base Deductions | - | (5,449,116,517) | (5,449,116,517) | | | (5,449,116,517) |
| 60 | | | | | | |
| 61 Total Rate Base: | - | 5,269,659,203 | 5,269,659,203 | | | 5,269,659,203 |
| 62 | | | | | | |
| 63 Return on Rate Base | | | 6.021% | | | 7.465% |
| 64 | | | | | | |
| 65 Return on Equity | | | 6.762% | | | 9.650% |

**PacifiCorp**
**OREGON**
**Normalized Results of Operations - 2020 PROTOCOL**
**Twelve Months Ending December 31, 2025**

## GENERAL RATE CASE RESULTS

| | | (1) | (2) | (3) (1) + (2) |
|---|---|---|---|---|
| | | Total Adjusted Results | **GRC** Price Change | Total Normalized Results with Price Change |
| 1 | Operating Revenues: | | | |
| 2 | General Business Revenues | 1,076,524,475 | 127,635,788 | 1,204,160,262 |
| 3 | Interdepartmental | - | | - |
| 4 | Special Sales | - | | - |
| 5 | Other Operating Revenues | 71,672,999 | | 71,672,999 |
| 6 | Total Operating Revenues | 1,148,197,474 | 127,635,788 | 1,275,833,262 |
| 7 | | | | |
| 8 | Operating Expenses: | | | |
| 9 | Steam Production | 88,668,797 | | 88,668,797 |
| 10 | Nuclear Production | - | | - |
| 11 | Hydro Production | 13,594,108 | | 13,594,108 |
| 12 | Other Power Supply | 30,369,149 | | 30,369,149 |
| 13 | Transmission | 19,610,833 | | 19,610,833 |
| 14 | Distribution | 114,542,254 | | 114,542,254 |
| 15 | Customer Accounting | 28,163,160 | 654,012 | 28,817,171 |
| 16 | Customer Service & Info | 5,298,846 | | 5,298,846 |
| 17 | Sales | - | | - |
| 18 | Administrative & General | 61,765,305 | | 61,765,305 |
| 19 | | | | |
| 20 | Total O&M Expenses | 362,012,451 | 654,012 | 362,666,463 |
| 21 | | | | |
| 22 | Depreciation | 317,074,767 | | 317,074,767 |
| 23 | Amortization | 27,809,318 | | 27,809,318 |
| 24 | Taxes Other Than Income | 100,593,896 | 2,969,278 | 103,563,174 |
| 25 | Income Taxes - Federal | 40,106,039 | 24,860,289 | 64,966,329 |
| 26 | Income Taxes - State | 9,315,392 | 5,630,167 | 14,945,559 |
| 27 | Income Taxes - Def Net | (8,550,148) | | (8,550,148) |
| 28 | Investment Tax Credit Adj. | - | | - |
| 29 | Misc Revenue & Expense | (30,006) | | (30,006) |
| 30 | | | | |
| 31 | Total Operating Expenses: | 848,331,709 | 34,113,747 | 882,445,456 |
| 32 | | | | |
| 33 | Operating Rev For Return: | 299,865,765 | 93,522,041 | 393,387,806 |
| 34 | | | | |
| 35 | Rate Base: | | | |
| 36 | Electric Plant In Service | 10,383,366,153 | | 10,383,366,153 |
| 37 | Plant Held for Future Use | - | | - |
| 38 | Misc Deferred Debits | 96,395,604 | | 96,395,604 |
| 39 | Elec Plant Acq Adj | 703,248 | | 703,248 |
| 40 | Pension | - | | - |
| 41 | Prepayments | 16,838,184 | | 16,838,184 |
| 42 | Fuel Stock | 43,544,178 | | 43,544,178 |
| 43 | Material & Supplies | 129,822,071 | | 129,822,071 |
| 44 | Working Capital | 48,204,849 | | 48,204,849 |
| 45 | Weatherization Loans | - | | - |
| 46 | Misc Rate Base | (98,566) | | (98,566) |
| 47 | | | | |
| 48 | Total Electric Plant: | 10,718,775,721 | | 10,718,775,721 |
| 49 | | | | |
| 50 | Rate Base Deductions: | | | |
| 51 | Accum Prov For Deprec | (4,043,129,802) | | (4,043,129,802) |
| 52 | Accum Prov For Amort | (229,765,382) | | (229,765,382) |
| 53 | Accum Def Income Tax | (696,410,395) | | (696,410,395) |
| 54 | Unamortized ITC | (40,918) | | (40,918) |
| 55 | Customer Adv For Const | (46,658,522) | | (46,658,522) |
| 56 | Customer Service Deposits | - | | - |
| 57 | Misc Rate Base Deductions | (433,111,498) | | (433,111,498) |
| 58 | | | | |
| 59 | Total Rate Base Deductions | (5,449,116,517) | | (5,449,116,517) |
| 60 | | | | |
| 61 | Total Rate Base: | 5,269,659,203 | | 5,269,659,203 |
| 62 | | | | |
| 63 | Return on Rate Base | 5.690% | | 7.465% |
| 64 | | | | |
| 65 | Return on Equity | 6.101% | | 9.650% |
| 66 | | | | |
| 67 | TAX CALCULATION: | | | |
| 68 | Operating Revenue | 340,737,048 | 124,012,498 | 464,749,546 |
| 69 | Other Deductions | | | |
| 70 | Interest (AFUDC) | (65,590,851) | - | (65,590,851) |
| 71 | Interest | 139,091,179 | - | 139,091,179 |
| 72 | Schedule "M" Additions | 431,417,541 | - | 431,417,541 |
| 73 | Schedule "M" Deductions | 498,295,283 | - | 498,295,283 |
| 74 | Income Before Tax | 200,358,978 | 124,012,498 | 324,371,476 |
| 75 | | | | |
| 76 | State Income Taxes | 9,315,392 | 5,630,167 | 14,945,559 |
| 77 | Taxable Income | 191,043,587 | 118,382,331 | 309,425,917 |
| 78 | | | | |
| 79 | Federal Income Taxes + Other | 40,106,039 | 24,860,289 | 64,966,329 |

**PacifiCorp**
**OREGON**
**Normalized Results of Operations - 2020 PROTOCOL**
**Twelve Months Ending December 31, 2025**

## TRANSITION ADJUSTMENT MECHANISM RESULTS

| | | (1) | (2) | (3) (1) + (2) |
|---|---|---|---|---|
| | | Total Adjusted Results | **TAM** Price Change | Total Normalized Results with Price Change |
| 1 | Operating Revenues: | | | |
| 2 | General Business Revenues | 604,412,863 | (23,119,457) | 581,293,406 |
| 3 | Interdepartmental | - | | - |
| 4 | Special Sales | 88,412,673 | | 88,412,673 |
| 5 | Other Operating Revenues | - | | - |
| 6 | Total Operating Revenues | 692,825,536 | (23,119,457) | 669,706,079 |
| 7 | | | | |
| 8 | Operating Expenses: | | | |
| 9 | Steam Production | 188,225,095 | | 188,225,095 |
| 10 | Nuclear Production | - | | - |
| 11 | Hydro Production | - | | - |
| 12 | Other Power Supply | 517,116,600 | | 517,116,600 |
| 13 | Transmission | 51,511,038 | | 51,511,038 |
| 14 | Distribution | - | | - |
| 15 | Customer Accounting | - | - | - |
| 16 | Customer Service & Info | - | | - |
| 17 | Sales | - | | - |
| 18 | Administrative & General | - | | - |
| 19 | | | | |
| 20 | Total O&M Expenses | 756,852,733 | - | 756,852,733 |
| 21 | | | | |
| 22 | Depreciation | - | | - |
| 23 | Amortization | - | | - |
| 24 | Taxes Other Than Income | - | - | - |
| 25 | Income Taxes - Federal | (78,555,531) | (4,634,665) | (83,190,197) |
| 26 | Income Taxes - State | (2,906,835) | (1,049,623) | (3,956,458) |
| 27 | Income Taxes - Def Net | - | | - |
| 28 | Investment Tax Credit Adj. | - | | - |
| 29 | Misc Revenue & Expense | - | | - |
| 30 | | | | |
| 31 | Total Operating Expenses: | 675,390,367 | (5,684,288) | 669,706,079 |
| 32 | | | | |
| 33 | Operating Rev For Return: | 17,435,169 | (17,435,169) | - |
| 34 | | | | |
| 35 | Rate Base: | | | |
| 36 | Electric Plant In Service | - | | - |
| 37 | Plant Held for Future Use | - | | - |
| 38 | Misc Deferred Debits | - | | - |
| 39 | Elec Plant Acq Adj | - | | - |
| 40 | Pension | - | | - |
| 41 | Prepayments | - | | - |
| 42 | Fuel Stock | - | | - |
| 43 | Material & Supplies | - | | - |
| 44 | Working Capital | - | | - |
| 45 | Weatherization Loans | - | | - |
| 46 | Misc Rate Base | - | | - |
| 47 | | | | |
| 48 | Total Electric Plant: | - | | - |
| 49 | | | | |
| 50 | Rate Base Deductions: | | | |
| 51 | Accum Prov For Deprec | - | | - |
| 52 | Accum Prov For Amort | - | | - |
| 53 | Accum Def Income Tax | - | | - |
| 54 | Unamortized ITC | - | | - |
| 55 | Customer Adv For Const | - | | - |
| 56 | Customer Service Deposits | - | | - |
| 57 | Misc Rate Base Deductions | - | | - |
| 58 | | | | |
| 59 | Total Rate Base Deductions | - | | - |
| 60 | | | | |
| 61 | Total Rate Base: | - | | - |
| 62 | | | | |
| 63 | Return on Rate Base | N/A | | N/A |
| 64 | | | | |
| 65 | Return on Equity | N/A | | N/A |
| 66 | | | | |
| 67 | TAX CALCULATION: | | | |
| 68 | Operating Revenue | (64,027,198) | (23,119,457) | (87,146,655) |
| 69 | Other Deductions | | | |
| 70 | Interest (AFUDC) | - | - | - |
| 71 | Interest | - | - | - |
| 72 | Schedule "M" Additions | - | - | - |
| 73 | Schedule "M" Deductions | - | - | - |
| 74 | Income Before Tax | (64,027,198) | (23,119,457) | (87,146,655) |
| 75 | | | | |
| 76 | State Income Taxes | (2,906,835) | (1,049,623) | (3,956,458) |
| 77 | Taxable Income | (61,120,363) | (22,069,834) | (83,190,197) |
| 78 | | | | |
| 79 | Federal Income Taxes + Other | (78,555,531) | (4,634,665) | (83,190,197) |

**PacifiCorp**
**OREGON**
**Normalized Results of Operations - 2020 PROTOCOL**
**Twelve Months Ending December 31, 2025**

| | | (1) Total Adjusted Results | (2) Price Change | (3) Results with Price Change |
|---|---|---|---|---|
| 1 | Operating Revenues: | | | |
| 2 | General Business Revenues | 1,680,937,338 | 104,516,331 | 1,785,453,669 |
| 3 | Interdepartmental | - | | |
| 4 | Special Sales | 88,412,673 | | |
| 5 | Other Operating Revenues | 71,672,999 | | |
| 6 | Total Operating Revenues | 1,841,023,010 | | |
| 7 | | | | |
| 8 | Operating Expenses: | | | |
| 9 | Steam Production | 276,893,892 | | |
| 10 | Nuclear Production | - | | |
| 11 | Hydro Production | 13,594,108 | | |
| 12 | Other Power Supply | 547,485,749 | | |
| 13 | Transmission | 71,121,871 | | |
| 14 | Distribution | 114,542,254 | | |
| 15 | Customer Accounting | 28,163,160 | 654,012 | 28,817,171 |
| 16 | Customer Service & Info | 5,298,846 | | |
| 17 | Sales | - | | |
| 18 | Administrative & General | 61,765,305 | | |
| 19 | | | | |
| 20 | Total O&M Expenses | 1,118,865,185 | | |
| 21 | | | | |
| 22 | Depreciation | 317,074,767 | | |
| 23 | Amortization | 27,809,318 | | |
| 24 | Taxes Other Than Income | 100,593,896 | 2,969,278 | 103,563,174 |
| 25 | Income Taxes - Federal | (38,449,492) | 20,225,624 | (18,223,868) |
| 26 | Income Taxes - State | 6,408,557 | 4,580,544 | 10,989,101 |
| 27 | Income Taxes - Def Net | (8,550,148) | | |
| 28 | Investment Tax Credit Adj. | - | | |
| 29 | Misc Revenue & Expense | (30,006) | | |
| 30 | | | | |
| 31 | Total Operating Expenses: | 1,523,722,077 | 28,429,458 | 1,552,151,535 |
| 32 | | | | |
| 33 | Operating Rev For Return: | 317,300,933 | 76,086,873 | 393,387,806 |
| 34 | | | | |
| 35 | Rate Base: | | | |
| 36 | Electric Plant In Service | 10,383,366,153 | | |
| 37 | Plant Held for Future Use | - | | |
| 38 | Misc Deferred Debits | 96,395,604 | | |
| 39 | Elec Plant Acq Adj | 703,248 | | |
| 40 | Pensions | - | | |
| 41 | Prepayments | 16,838,184 | | |
| 42 | Fuel Stock | 43,544,178 | | |
| 43 | Material & Supplies | 129,822,071 | | |
| 44 | Working Capital | 48,204,849 | | |
| 45 | Weatherization Loans | - | | |
| 46 | Misc Rate Base | (98,566) | | |
| 47 | | | | |
| 48 | Total Electric Plant: | 10,718,775,721 | - | 10,718,775,721 |
| 49 | | | | |
| 50 | Rate Base Deductions: | | | |
| 51 | Accum Prov For Deprec | (4,043,129,802) | | |
| 52 | Accum Prov For Amort | (229,765,382) | | |
| 53 | Accum Def Income Tax | (696,410,395) | | |
| 54 | Unamortized ITC | (40,918) | | |
| 55 | Customer Adv For Const | (46,658,522) | | |
| 56 | Customer Service Deposits | - | | |
| 57 | Misc Rate Base Deductions | (433,111,498) | | |
| 58 | | | | |
| 59 | Total Rate Base Deductions | (5,449,116,517) | - | (5,449,116,517) |
| 60 | | | | |
| 61 | Total Rate Base: | 5,269,659,203 | - | 5,269,659,203 |
| 62 | | | | |
| 63 | Return on Rate Base | 6.021% | | 7.465% |
| 64 | | | | |
| 65 | Return on Equity | 6.762% | | 9.650% |
| 66 | | | | |
| 67 | TAX CALCULATION: | | | |
| 68 | Operating Revenue | 276,709,850 | 100,893,041 | 377,602,891 |
| 69 | Other Deductions | | | |
| 70 | Interest (AFUDC) | (65,590,851) | - | (65,590,851) |
| 71 | Interest | 139,091,179 | - | 139,091,179 |
| 72 | Schedule "M" Additions | 431,417,541 | - | 431,417,541 |
| 73 | Schedule "M" Deductions | 498,295,283 | - | 498,295,283 |
| 74 | Income Before Tax | 136,331,781 | 100,893,041 | 237,224,822 |
| 75 | | | | |
| 76 | State Income Taxes | 6,408,557 | 4,580,544 | 10,989,101 |
| 77 | Taxable Income | 129,923,224 | 96,312,497 | 226,235,721 |
| 78 | | | | |
| 79 | Federal Income Taxes + Other | (38,449,492) | 20,225,624 | (18,223,868) |

**PacifiCorp**
**OREGON**
**Normalized Results of Operations - 2020 PROTOCOL**
**Twelve Months Ending December 31, 2025**

| | | | |
|---|---|---|---|
| Net Rate Base | $ | 5,269,659,203 | Ref. Page 1.1_R |
| Return on Rate Base Requested | | 7.47% | Ref. Page 2.1_R |
| Revenues Required to Earn Requested Return | | 393,387,806 | |
| Less Current Operating Revenues | | (317,300,933) | |
| Increase to Current Revenues | | 76,086,873 | |
| Net to Gross Bump-up | | 137.36% | |
| Price Change Required for Requested Return | $ | 104,516,331 | |
| Requested Price Change | $ | 104,516,331 | |
| Uncollectible Percent | | 0.626% | Ref. Page 1.6_R |
| Increased Uncollectible Expense | $ | 654,012 | |
| Requested Price Change | $ | 104,516,331 | |
| Franchise Tax | | 2.276% | Ref. Page 1.6_R |
| Revenue Tax | | 0.000% | Ref. Page 1.6_R |
| Resource Supplier Tax | | 0.115% | Ref. Page 1.6_R |
| PUC Fees Based on General Business Revenues | | 0.450% | Ref. Page 1.6_R |
| Increase Taxes Other Than Income | $ | 2,969,278 | |
| Requested Price Change | $ | 104,516,331 | |
| Uncollectible Expense | | (654,012) | |
| Taxes Other Than Income | | (2,969,278) | |
| Income Before Taxes | $ | 100,893,041 | |
| State Effective Tax Rate | | 4.54% | Ref. Page 2.0_R |
| State Income Taxes | $ | 4,580,544 | |
| Taxable Income | $ | 96,312,497 | |
| Federal Income Tax Rate | | 21.00% | Ref. Page 2.0_R |
| Federal Income Taxes | $ | 20,225,624 | |
| Operating Income | | 100.000% | |
| Net Operating Income | | 72.799% | Ref. Page 1.6_R |
| Net to Gross Bump-Up | | 137.36% | |

**PacifiCorp**
**OREGON**
**Normalized Results of Operations - 2020 PROTOCOL**
**Twelve Months Ending December 31, 2025**

| | | |
|---|---|---|
| Operating Revenue | 100.000% | |
| Operating Deductions | | |
| Uncollectible Accounts | 0.626% | See Note (1) Below |
| Taxes Other - Franchise Tax | 2.276% | |
| Taxes Other - Revenue Tax | 0.000% | |
| Taxes Other - Resource Supplier | 0.115% | |
| PUC Fees Based on General Business Revenues | 0.450% | |
| Sub-Total | 96.533% | |
| State Income Tax @ 4.54% | 4.383% | |
| Sub-Total | 92.151% | |
| Federal Income Tax @ 21.00% | 19.352% | |
| Net Operating Income | 72.799% | |

| | | |
|---|---|---|
| (1) Uncollectible Accounts = | 10,518,476 | Pg 2.11_R, OREGON Situs from Account 904 |
| | 1,680,937,338 | Pg. 2.2_R, General Business Revenues |

**PacifiCorp**
**Oregon General Rate Case**
**Adjustment Summary**
**Twelve Months Ending December 31, 2025**

| | | | Tab 3 | Tab 4 | Tab 5 | Tab 6 |
|---|---|---|---|---|---|---|
| | TOTAL COMPANY UNADJUSTED RESULTS JUNE 2023 | OREGON ALLOCATED UNADJUSTED RESULTS JUNE 2023 | Revenue Adjustments | O&M Adjustments | Net Power Cost Adjustments | Depreciation & Amortization Adjustments |
| 1 Operating Revenues: | | | | | | |
| 2 General Business Revenues | 5,314,367,832 | 1,399,023,529 | 280,144,493 | 1,769,316 | - | - |
| 3 Interdepartmental | - | - | - | - | - | - |
| 4 Special Sales | 276,874,873 | 70,586,388 | - | - | 17,826,285 | - |
| 5 Other Operating Revenues | 272,845,382 | 74,297,451 | 1,450,937 | - | - | - |
| 6 Total Operating Revenues | 5,864,088,087 | 1,543,907,367 | 281,595,430 | 1,769,316 | 17,826,285 | - |
| 7 | | | | | | |
| 8 Operating Expenses: | | | | | | |
| 9 Steam Production | 929,501,268 | 246,336,079 | - | 283,685 | 26,827,464 | 3,818,882 |
| 10 Nuclear Production | - | - | - | - | - | - |
| 11 Hydro Production | 42,657,730 | 11,468,171 | - | 2,689,386 | - | - |
| 12 Other Power Supply | 1,454,847,175 | 520,565,938 | - | 2,644,070 | 23,376,731 | - |
| 13 Transmission | 247,176,958 | 66,310,208 | - | (1,954,519) | 6,766,182 | - |
| 14 Distribution | 282,601,391 | 104,588,448 | - | 9,124,295 | - | - |
| 15 Customer Accounting | 80,792,201 | 23,991,155 | - | 4,172,005 | - | - |
| 16 Customer Service & Info | 158,979,871 | 4,916,333 | - | 382,513 | - | - |
| 17 Sales | - | - | - | - | - | - |
| 18 Administrative & General | 630,431,721 | 172,101,036 | - | (110,810,560) | - | - |
| 19 | | | | | | |
| 20 Total O&M Expenses | 3,826,988,315 | 1,150,277,368 | - | (93,469,126) | 56,970,377 | 3,818,882 |
| 21 | | | | | | |
| 22 Depreciation | 993,452,379 | 271,108,388 | - | - | - | 40,255,866 |
| 23 Amortization | 76,333,322 | 15,984,719 | - | - | - | (2,716,107) |
| 24 Taxes Other Than Income | 188,692,373 | 74,630,102 | - | 6,690,549 | - | - |
| 25 Income Taxes - Federal | (253,281,170) | (73,709,627) | 56,439,197 | 18,651,924 | (7,854,659) | (3,029,860) |
| 26 Income Taxes - State | (2,828,341) | (1,608,219) | 12,781,916 | 4,224,145 | (1,778,863) | (686,179) |
| 27 Income Taxes - Def Net | 55,172,095 | (9,956,034) | - | (1,865,118) | - | (938,932) |
| 28 Investment Tax Credit Adj. | (910,300) | - | - | - | - | - |
| 29 Misc Revenue & Expense | (396,311) | (50,000) | - | 19,995 | - | - |
| 30 | | | | | | |
| 31 Total Operating Expenses: | 4,883,222,363 | 1,426,676,697 | 69,221,112 | (65,747,631) | 47,336,855 | 36,703,670 |
| 32 | | | | | | |
| 33 Operating Rev For Return: | 980,865,723 | 117,230,670 | 212,374,318 | 67,516,947 | (29,510,570) | (36,703,670) |
| 34 | | | | | | |
| 35 Rate Base: | | | | | | |
| 36 Electric Plant In Service | 32,886,279,146 | 9,145,444,083 | - | - | - | - |
| 37 Plant Held for Future Use | 14,174,575 | 7,461,409 | - | - | - | - |
| 38 Misc Deferred Debits | 1,636,633,742 | 182,518,703 | - | - | - | - |
| 39 Elec Plant Acq Adj | 11,954,169 | 723,506 | - | - | - | - |
| 40 Pensions | 104,951,393 | 28,783,408 | - | - | - | - |
| 41 Prepayments | 96,171,480 | 16,838,184 | - | - | - | - |
| 42 Fuel Stock | 137,605,040 | 36,243,955 | - | - | - | - |
| 43 Material & Supplies | 407,130,439 | 129,822,071 | - | - | - | - |
| 44 Working Capital | 127,419,617 | 47,141,218 | 2,100,248 | (1,938,875) | 1,436,254 | 3,120 |
| 45 Weatherization Loans | 224,530,257 | - | - | - | - | - |
| 46 Misc Rate Base | - | - | - | - | - | - |
| 47 | | | | | | |
| 48 Total Electric Plant: | 35,646,849,859 | 9,594,976,538 | 2,100,248 | (1,938,875) | 1,436,254 | 3,120 |
| 49 | | | | | | |
| 50 Rate Base Deductions: | | | | | | |
| 51 Accum Prov For Deprec | (11,020,394,328) | (3,223,614,207) | - | - | - | (817,609,078) |
| 52 Accum Prov For Amort | (731,617,791) | (207,213,607) | - | - | - | (25,921,413) |
| 53 Accum Def Income Tax | (2,927,745,908) | (674,015,477) | - | (38,564,469) | - | 1,988,755 |
| 54 Unamortized ITC | (2,260,839) | (45,635) | - | - | - | - |
| 55 Customer Adv For Const | (193,419,991) | (73,982,464) | - | - | - | - |
| 56 Customer Service Deposits | - | - | - | - | - | - |
| 57 Misc Rate Base Deductions | (2,624,994,265) | (610,776,749) | - | 156,851,573 | - | (8,088,788) |
| 58 | | | | | | |
| 59 Total Rate Base Deductions | (17,500,433,122) | (4,789,648,140) | - | 118,287,105 | - | (849,630,523) |
| 60 | | | | | | |
| 61 Total Rate Base: | 18,146,416,737 | 4,805,328,398 | 2,100,248 | 116,348,229 | 1,436,254 | (849,627,403) |
| 62 | | | | | | |
| 63 Return on Rate Base | | 2.440% | 4.417% | 1.209% | -0.602% | 0.655% |
| 64 | | | | | | |
| 65 Return on Equity | | -0.401% | 8.833% | 2.418% | -1.203% | 1.311% |
| 66 | | | | | | |
| 67 TAX CALCULATION: | | | | | | |
| 68 Operating Revenue | | 31,956,790 | 281,595,430 | 88,527,898 | (39,144,093) | (41,358,641) |
| 69 Other Deductions | | | | | | |
| 70 Interest (AFUDC) | | (27,057,087) | - | - | - | - |
| 71 Interest | | 126,835,298 | 55,435 | 3,070,979 | 37,910 | (22,425,677) |
| 72 Schedule "M" Additions | | 349,040,084 | - | 7,585,912 | - | 3,818,882 |
| 73 Schedule "M" Deductions | | 382,368,862 | - | - | - | - |
| 74 Income Before Tax | | (101,150,200) | 281,539,995 | 93,042,831 | (39,182,002) | (15,114,082) |
| 75 | | | | | | |
| 76 State Income Taxes | | (1,608,219) | 12,781,916 | 4,224,145 | (1,778,863) | (686,179) |
| 77 Taxable Income | | (99,541,981) | 268,758,079 | 88,818,686 | (37,403,139) | (14,427,902) |
| 78 | | | | | | |
| 79 Federal Income Taxes + Other | | (73,709,627) | 56,439,197 | 18,651,924 | (7,854,659) | (3,029,860) |
| APPROXIMATE PRICE CHANGE | | 331,685,456 | (291,517,421) | (80,765,766) | 40,684,319 | (36,706,897) |

**PacifiCorp**
**Oregon General Rate Case**
**Adjustment Summary**
**Twelve Months Ending December 31, 2025**

| | | Tab 7 | Tab 8 | REPLY | OR Allocated |
|---|---|---|---|---|---|
| | | Tax Adjustments | Rate Base Adjustments | Reply Adjustments NEW | Results of Operations December 2025 |
| 1 | Operating Revenues: | | | | |
| 2 | General Business Revenues | - | - | - | 1,680,937,338 |
| 3 | Interdepartmental | - | - | - | - |
| 4 | Special Sales | - | - | - | 88,412,673 |
| 5 | Other Operating Revenues | - | (4,075,388) | - | 71,672,999 |
| 6 | Total Operating Revenues | - | (4,075,388) | - | 1,841,023,010 |
| 7 | | | | | |
| 8 | Operating Expenses: | | | | |
| 9 | Steam Production | - | (372,219) | - | 276,893,892 |
| 10 | Nuclear Production | - | - | - | - |
| 11 | Hydro Production | - | (563,449) | - | 13,594,108 |
| 12 | Other Power Supply | - | 899,010 | - | 547,485,749 |
| 13 | Transmission | - | - | - | 71,121,871 |
| 14 | Distribution | - | 829,511 | - | 114,542,254 |
| 15 | Customer Accounting | - | - | - | 28,163,160 |
| 16 | Customer Service & Info | - | - | - | 5,298,846 |
| 17 | Sales | - | - | - | - |
| 18 | Administrative & General | - | 474,830 | - | 61,765,305 |
| 19 | | | | | |
| 20 | Total O&M Expenses | - | 1,267,683 | - | 1,118,865,185 |
| 21 | | | | | |
| 22 | Depreciation | - | 5,713,429 | (2,916) | 317,074,767 |
| 23 | Amortization | - | 17,633,929 | (3,093,223) | 27,809,318 |
| 24 | Taxes Other Than Income | 19,273,245 | - | - | 100,593,896 |
| 25 | Income Taxes - Federal | (29,056,360) | (3,843,113) | 3,953,006 | (38,449,492) |
| 26 | Income Taxes - State | (6,549,130) | (870,359) | 895,246 | 6,408,557 |
| 27 | Income Taxes - Def Net | 18,420,095 | (10,331,715) | (3,878,445) | (8,550,148) |
| 28 | Investment Tax Credit Adj. | - | - | - | - |
| 29 | Misc Revenue & Expense | - | - | - | (30,006) |
| 30 | | | | | |
| 31 | Total Operating Expenses: | 2,087,850 | 9,569,854 | (2,126,331) | 1,523,722,077 |
| 32 | | | | | |
| 33 | Operating Rev For Return: | (2,087,850) | (13,645,242) | 2,126,331 | 317,300,933 |
| 34 | | | | | |
| 35 | Rate Base: | | | | |
| 36 | Electric Plant In Service | - | 1,280,362,797 | (42,440,727) | 10,383,366,153 |
| 37 | Plant Held for Future Use | - | (7,461,409) | - | - |
| 38 | Misc Deferred Debits | - | (86,123,100) | - | 96,395,604 |
| 39 | Elec Plant Acq Adj | - | (20,258) | - | 703,248 |
| 40 | Pensions | - | (28,783,408) | - | - |
| 41 | Prepayments | - | - | - | 16,838,184 |
| 42 | Fuel Stock | - | 7,300,223 | - | 43,544,178 |
| 43 | Material & Supplies | - | - | - | 129,822,071 |
| 44 | Working Capital | (495,539) | (188,679) | 147,102 | 48,204,849 |
| 45 | Weatherization Loans | - | - | - | - |
| 46 | Misc Rate Base | - | - | (98,566) | (98,566) |
| 47 | | | | | |
| 48 | Total Electric Plant: | (495,539) | 1,165,086,166 | (42,392,192) | 10,718,775,721 |
| 49 | | | | | |
| 50 | Rate Base Deductions: | | | | |
| 51 | Accum Prov For Deprec | - | (1,906,517) | - | (4,043,129,802) |
| 52 | Accum Prov For Amort | - | 276,415 | 3,093,223 | (229,765,382) |
| 53 | Accum Def Income Tax | (34,395,710) | 41,418,474 | 7,158,032 | (696,410,395) |
| 54 | Unamortized ITC | 4,716 | - | - | (40,918) |
| 55 | Customer Adv For Const | - | 27,323,942 | - | (46,658,522) |
| 56 | Customer Service Deposits | - | - | - | - |
| 57 | Misc Rate Base Deductions | 29,710,341 | (807,875) | - | (433,111,498) |
| 58 | | | | | |
| 59 | Total Rate Base Deductions | (4,680,653) | 66,304,439 | 10,251,255 | (5,449,116,517) |
| 60 | | | | | |
| 61 | Total Rate Base: | (5,176,192) | 1,231,390,605 | (32,140,936) | 5,269,659,203 |
| 62 | | | | | |
| 63 | Return on Rate Base | -0.041% | -2.134% | 0.077% | 6.021% |
| 64 | | | | | |
| 65 | Return on Equity | -0.082% | -4.267% | 0.153% | 6.762% |
| 66 | | | | | |
| 67 | TAX CALCULATION: | | | | |
| 68 | Operating Revenue | (19,273,245) | (28,690,429) | 3,096,139 | 276,709,850 |
| 69 | Other Deductions | | | | |
| 70 | Interest (AFUDC) | (38,533,764) | - | - | (65,590,851) |
| 71 | Interest | (136,624) | 32,502,210 | (848,351) | 139,091,179 |
| 72 | Schedule "M" Additions | 40,628,028 | 33,437,860 | (3,093,223) | 431,417,541 |
| 73 | Schedule "M" Deductions | 143,378,120 | (8,583,880) | (18,867,819) | 498,295,283 |
| 74 | Income Before Tax | (83,352,948) | (19,170,899) | 19,719,086 | 136,331,781 |
| 75 | | | | | |
| 76 | State Income Taxes | (6,549,130) | (870,359) | 895,246 | 6,408,557 |
| 77 | Taxable Income | (76,803,818) | (18,300,540) | 18,823,839 | 129,923,224 |
| 78 | | | | | |
| 79 | Federal Income Taxes + Other | (29,056,360) | (3,843,113) | 3,953,006 | (38,449,492) |
| | APPROXIMATE PRICE CHANGE | 2,337,174 | 145,016,168 | (6,216,703) | 104,516,331 |

# Tab 0 - Renmpr

**PacifiCorp**
**RESULTS OF OPERATIONS**

USER SPECIFIC INFORMATION

| | |
|---|---|
| STATE: | OREGON |
| PERIOD: | TWELVE MONTHS ENDING DECEMBER 31, 2025 |
| FILE: | OR JAM Dec 2025 GRC |
| PREPARED BY: | Revenue Requirement Department |
| DATE: | 7/19/2024 |
| TIME: | 3:19:37 PM |
| TYPE OF RATE BASE: | Year End |
| ALLOCATION METHOD: | **2020 PROTOCOL** |
| FERC JURISDICTION: | Separate Jurisdiction |
| 8 OR 12 CP: | 12 Coincident Peaks |
| DEMAND % | 75% Demand |
| ENERGY % | 25% Energy |

TAX INFORMATION

| TAX RATE ASSUMPTIONS: | TAX RATE |
|---|---|
| FEDERAL RATE | 21.00% |
| STATE EFFECTIVE RATE | 4.54% |
| TAX GROSS UP FACTOR | 1.326 |
| FEDERAL/STATE COMBINED RATE | 24.587% |

CAPITAL STRUCTURE INFORMATION

| | CAPITAL STRUCTURE | EMBEDDED COST | WEIGHTED COST |
|---|---|---|---|
| DEBT | 49.99% | 5.28% | 2.64% |
| PREFERRED | 0.01% | 6.75% | 0.00% |
| COMMON | 50.00% | 9.65% | 4.83% |
| | 100.00% | | 7.47% |

OTHER INFORMATION

For information and support regarding capital structure and cost of debt, see testimony of Ms. Nikki L. Kobliha.
For information and support regarding return on common equity, see testimony of Ms. Ann E. Bulkley.

**2020 PROTOCOL**

## RESULTS OF OPERATIONS SUMMARY

| | Description of Account Summary: | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|
| 1 | Operating Revenues | | | | | |
| 2 | General Business Revenues | 2.2_R | 5,314,367,832 | 1,399,023,529 | 5,596,281,641 | 1,680,937,338 |
| 3 | Interdepartmental | 2.2_R | 0 | 0 | 0 | 0 |
| 4 | Special Sales | 2.2_R | 276,874,873 | 70,586,388 | 343,182,642 | 88,412,673 |
| 5 | Other Operating Revenues | 2.3_R | 272,845,382 | 74,297,451 | 274,261,754 | 71,672,999 |
| 6 | Total Operating Revenues | 2.3_R | 5,864,088,087 | 1,543,907,367 | 6,213,726,037 | 1,841,023,010 |
| 7 | | | | | | |
| 8 | Operating Expenses: | | | | | |
| 9 | Steam Production | 2.5_R | 929,501,268 | 246,336,079 | 1,045,312,352 | 276,893,892 |
| 10 | Nuclear Production | 2.5_R | 0 | 0 | 0 | 0 |
| 11 | Hydro Production | 2.6_R | 42,657,730 | 11,468,171 | 50,565,497 | 13,594,108 |
| 12 | Other Power Supply | 2.7_R, .8_R | 1,454,847,175 | 520,565,938 | 1,579,353,132 | 547,485,749 |
| 13 | Transmission | 2.9_R | 247,176,958 | 66,310,208 | 264,809,989 | 71,121,871 |
| 14 | Distribution | 2.10_R | 282,601,391 | 104,588,448 | 296,925,033 | 114,542,254 |
| 15 | Customer Accounting | 2.11_R | 80,792,201 | 23,991,155 | 87,173,667 | 28,163,160 |
| 16 | Customer Service & Infor | 2.12_R | 158,979,871 | 4,916,333 | 158,194,179 | 5,298,846 |
| 17 | Sales | 2.12_R | 0 | 0 | 0 | 0 |
| 18 | Administrative & General | 2.13_R | 630,431,721 | 172,101,036 | 176,893,481 | 61,765,305 |
| 19 | | | | | | |
| 20 | Total O & M Expenses | 2.13_R | 3,826,988,315 | 1,150,277,368 | 3,659,227,331 | 1,118,865,185 |
| 21 | | | | | | |
| 22 | Depreciation | 2.14_R | 993,452,379 | 271,108,388 | 1,182,574,929 | 317,074,767 |
| 23 | Amortization | 2.15_R | 76,333,322 | 15,984,719 | 89,210,916 | 27,809,318 |
| 24 | Taxes Other Than Income | 2.15_R | 188,692,373 | 74,630,102 | 249,409,461 | 100,593,896 |
| 25 | Income Taxes - Federal | 2.18_R | (253,281,170) | (73,709,627) | (111,275,580) | (38,449,492) |
| 26 | Income Taxes - State | 2.18_R | (2,828,341) | (1,608,219) | 37,325,856 | 6,408,557 |
| 27 | Income Taxes - Def Net | 2.16_R | 55,172,095 | (9,956,034) | (129,220,723) | (8,550,148) |
| 28 | Investment Tax Credit Adj. | 2.15_R | (910,300) | 0 | (471,305) | 0 |
| 29 | Misc Revenue & Expense | 2.3_R | (396,311) | (50,000) | (351,090) | (30,006) |
| 30 | | | | | | |
| 31 | Total Operating Expenses | 2.18_R | 4,883,222,363 | 1,426,676,697 | 4,976,429,795 | 1,523,722,077 |
| 32 | | | | | | |
| 33 | Operating Revenue for Return | | 980,865,723 | 117,230,670 | 1,237,296,242 | 317,300,933 |
| 34 | | | | | | |
| 35 | Rate Base: | | | | | |
| 36 | Electric Plant in Service | 2.26_R | 32,886,279,146 | 9,145,444,083 | 37,860,312,821 | 10,383,366,153 |
| 37 | Plant Held for Future Use | 2.26_R | 14,174,575 | 7,461,409 | 0 | 0 |
| 38 | Misc Deferred Debits | 2.28_R | 1,636,633,742 | 182,518,703 | 1,315,184,762 | 96,395,604 |
| 39 | Elec Plant Acq Adj | 2.26_R,.27_R | 11,954,169 | 723,506 | 11,878,818 | 703,248 |
| 40 | Pensions | 2.27_R | 104,951,393 | 28,783,408 | 0 | 0 |
| 41 | Prepayments | 2.28_R | 96,171,480 | 16,838,184 | 96,171,480 | 16,838,184 |
| 42 | Fuel Stock | 2.27_R | 137,605,040 | 36,243,955 | 165,321,317 | 43,544,178 |
| 43 | Material & Supplies | 2.28_R | 407,130,439 | 129,822,071 | 407,130,439 | 129,822,071 |
| 44 | Working Capital | 2.28_R | 127,419,617 | 47,141,218 | 125,394,152 | 48,204,849 |
| 45 | Weatherization Loans | 2.27_R | 224,530,257 | 0 | 224,530,257 | 0 |
| 46 | Miscellaneous Rate Base | 2.29_R | 0 | 0 | (98,566) | (98,566) |
| 47 | | | | | | |
| 48 | Total Electric Plant | | 35,646,849,859 | 9,594,976,538 | 40,205,825,480 | 10,718,775,721 |
| 49 | | | | | | |
| 50 | Rate Base Deductions: | | | | | |
| 51 | Accum Prov For Depr | 2.32_R | (11,020,394,328) | (3,223,614,207) | (13,661,526,090) | (4,043,129,802) |
| 52 | Accum Prov For Amort | 2.33_R | (731,617,791) | (207,213,607) | (811,341,845) | (229,765,382) |
| 53 | Accum Def Income Taxes | 2.30_R | (2,927,745,908) | (674,015,477) | (3,003,284,673) | (696,410,395) |
| 54 | Unamortized ITC | 2.30_R | (2,260,839) | (45,635) | (2,074,486) | (40,918) |
| 55 | Customer Adv for Const | 2.29_R | (193,419,991) | (73,982,464) | (193,419,991) | (46,658,522) |
| 56 | Customer Service Deposits | 2.29_R | 0 | 0 | 0 | 0 |
| 57 | Misc. Rate Base Deductions | 2.29_R | (2,624,994,265) | (610,776,749) | (2,058,185,179) | (433,111,498) |
| 58 | | | | | | |
| 59 | Total Rate Base Deductions | | (17,500,433,122) | (4,789,648,140) | (19,729,832,264) | (5,449,116,517) |
| 60 | | | | | | |
| 61 | Total Rate Base | | 18,146,416,737 | 4,805,328,398 | 20,475,993,217 | 5,269,659,203 |
| 62 | | | | | | |
| 63 | Return on Rate Base | | | 2.440% | | 6.021% |
| 64 | | | | | | |
| 65 | Return on Equity | | | -0.401% | | 6.762% |
| 66 | Net Power Costs | | 2,380,539,065 | 629,382,892 | 2,552,463,674 | 668,440,061 |
| 67 | 100 Basis Points in Equity: | | | | | |
| 68 | Revenue Requirement Impact | | 120,312,947 | 31,859,911 | 135,758,322 | 34,938,480 |
| 69 | Rate Base Decrease | | (1,536,455,367) | (817,344,629) | (1,564,804,598) | (404,035,652) |

| | 2020 PROTOCOL<br>Year End<br>FERC<br>ACCT | DESCRIP | FACTOR | Ref | JUNE 2023<br>UNADJUSTED RESULTS<br>TOTAL | <br><br>OREGON | DECEMBER 2025<br>NORMALIZED RESULTS<br>TOTAL | <br><br>OREGON |
|---|---|---|---|---|---|---|---|---|
| 70 | Sales to Ultimate Customers | | | | | | | |
| 71 | 440 | Residential Sales | | | | | | |
| 72 | | | S | | 2,192,507,229 | 726,305,943 | 2,270,593,606 | 804,392,320 |
| 73 | | | | | | | | |
| 74 | | | | B1 | 2,192,507,229 | 726,305,943 | 2,270,593,606 | 804,392,320 |
| 75 | | | | | | | | |
| 76 | 442 | Commercial & Industrial Sales | | | | | | |
| 77 | | | S | | 3,106,997,795 | 667,790,073 | 3,312,207,316 | 872,999,594 |
| 78 | | | SE | | - | - | - | - |
| 79 | | | SG | | - | - | - | - |
| 80 | | | | | | | | |
| 81 | | | | | | | | |
| 82 | | | | B1 | 3,106,997,795 | 667,790,073 | 3,312,207,316 | 872,999,594 |
| 83 | | | | | | | | |
| 84 | 444 | Public Street & Highway Lighting | | | | | | |
| 85 | | | S | | 14,862,807 | 4,927,512 | 13,480,719 | 3,545,424 |
| 86 | | | SO | | - | - | - | - |
| 87 | | | | B1 | 14,862,807 | 4,927,512 | 13,480,719 | 3,545,424 |
| 88 | | | | | | | | |
| 89 | 445 | Other Sales to Public Authority | | | | | | |
| 90 | | | S | | - | - | - | - |
| 91 | | | | | | | | |
| 92 | | | | B1 | - | - | - | - |
| 93 | | | | | | | | |
| 94 | 448 | Interdepartmental | | | | | | |
| 95 | | | S | | - | - | - | - |
| 96 | | | SO | | - | - | - | - |
| 97 | | | | B1 | - | - | - | - |
| 98 | | | | | | | | |
| 99 | **Total Sales to Ultimate Customers** | | | **B1** | **5,314,367,832** | **1,399,023,529** | **5,596,281,641** | **1,680,937,338** |
| 100 | | | | | | | | |
| 101 | | | | | | | | |
| 102 | | | | | | | | |
| 103 | 447 | Sales for Resale-Non NPC | | | | | | |
| 104 | | | S | | 14,317,310 | - | 14,317,310 | - |
| 105 | | | | B1 | 14,317,310 | - | 14,317,310 | - |
| 106 | | | | | | | | |
| 107 | 447NPC | Sales for Resale-NPC | | | | | | |
| 108 | | | SG | | 262,557,563 | 70,586,388 | 328,865,333 | 88,412,673 |
| 109 | | | SE | | - | - | - | - |
| 110 | | | SG | | - | - | - | - |
| 111 | | | | B1 | 262,557,563 | 70,586,388 | 328,865,333 | 88,412,673 |
| 112 | | | | | | | | |
| 113 | | Total Sales for Resale | | B1 | 276,874,873 | 70,586,388 | 343,182,642 | 88,412,673 |
| 114 | | | | | | | | |
| 115 | 449 | Provision for Rate Refund | | | | | | |
| 116 | | | S | | - | - | - | - |
| 117 | | | SG | | - | - | - | - |
| 118 | | | | | | | | |
| 119 | | | | | | | | |
| 120 | | | | B1 | - | - | - | - |
| 121 | | | | | | | | |
| 122 | **Total Sales from Electricity** | | | **B1** | **5,591,242,705** | **1,469,609,916** | **5,939,464,283** | **1,769,350,010** |
| 123 | 450 | Forfeited Discounts & Interest | | | | | | |
| 124 | | | S | | 12,852,263 | 5,583,122 | 12,852,263 | 5,583,122 |
| 125 | | | SO | | - | - | - | - |
| 126 | | | | B1 | 12,852,263 | 5,583,122 | 12,852,263 | 5,583,122 |
| 127 | | | | | | | | |
| 128 | 451 | Misc Electric Revenue | | | | | | |
| 129 | | | S | | 7,209,105 | 1,520,715 | 7,209,105 | 1,520,715 |
| 130 | | | SG | | - | - | - | - |
| 131 | | | SO | | - | - | - | - |
| 132 | | | | B1 | 7,209,105 | 1,520,715 | 7,209,105 | 1,520,715 |
| 133 | | | | | | | | |
| 134 | 453 | Water Sales | | | | | | |
| 135 | | | SG | | 4,980 | 1,339 | 4,980 | 1,339 |
| 136 | | | | B1 | 4,980 | 1,339 | 4,980 | 1,339 |
| 137 | | | | | | | | |
| 138 | 454 | Rent of Electric Property | | | | | | |
| 139 | | | S | | 12,652,950 | 5,282,389 | 12,652,950 | 5,282,389 |
| 140 | | | SG | | 3,696,909 | 993,883 | 3,696,909 | 993,883 |
| 141 | | | SG | | - | - | - | - |
| 142 | | | SO | | 3,363,987 | 922,589 | 3,363,987 | 922,589 |
| 143 | | | | B1 | 19,713,846 | 7,198,861 | 19,713,846 | 7,198,861 |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 144 | | | | | | | | |
| 145 | | | | | | | | |
| 146 | | | | | | | | |
| 147 | 456 | Other Electric Revenue | | | | | | |
| 148 | | | S | | 24,404,444 | 4,075,388 | 20,329,056 | - |
| 149 | | | CN | | - | - | - | - |
| 150 | | | SE | | 32,877,886 | 8,659,745 | 37,552,124 | 9,890,899 |
| 151 | | | SO | | 99,792 | 27,369 | 99,792 | 27,369 |
| 152 | | | SG | | 175,683,066 | 47,230,912 | 176,500,588 | 47,450,695 |
| 153 | | | | | | | | |
| 154 | | | | | | | | |
| 155 | | | | B1 | 233,065,189 | 59,993,414 | 234,481,561 | 57,368,962 |
| 156 | | | | | | | | |
| 157 | **Total Other Electric Revenues** | | | **B1** | **272,845,382** | **74,297,451** | **274,261,754** | **71,672,999** |
| 158 | | | | | | | | |
| 159 | **Total Electric Operating Revenues** | | | **B1** | **5,864,088,087** | **1,543,907,367** | **6,213,726,037** | **1,841,023,010** |
| 160 | | | | | | | | |
| 161 | Summary of Revenues by Factor | | | | | | | |
| 162 | | S | | | 5,385,803,904 | 1,415,485,143 | 5,663,642,325 | 1,693,323,564 |
| 163 | | CN | | | - | - | - | - |
| 164 | | SE | | | 32,877,886 | 8,659,745 | 37,552,124 | 9,890,899 |
| 165 | | SO | | | 3,463,779 | 949,958 | 3,463,779 | 949,958 |
| 166 | | SG | | | 441,942,518 | 118,812,521 | 509,067,809 | 136,858,589 |
| 167 | | DGP | | | - | - | - | - |
| 168 | | | | | | | | |
| 169 | Total Electric Operating Revenues | | | | 5,864,088,087 | 1,543,907,367 | 6,213,726,037 | 1,841,023,010 |
| 170 | Miscellaneous Revenues | | | | | | | |
| 171 | 41160 | Gain on Sale of Utility Plant - CR | | | | | | |
| 172 | | | S | | - | - | - | - |
| 173 | | | SG | | - | - | - | - |
| 174 | | | SO | | - | - | - | - |
| 175 | | | SG | | - | - | - | - |
| 176 | | | SG | | - | - | - | - |
| 177 | | | | B1 | - | - | - | - |
| 178 | | | | | | | | |
| 179 | 41170 | Loss on Sale of Utility Plant | | | | | | |
| 180 | | | S | | - | - | - | - |
| 181 | | | SG | | - | - | - | - |
| 182 | | | | B1 | - | - | - | - |
| 183 | | | | | | | | |
| 184 | 4118 | Gain from Emission Allowances | | | | | | |
| 185 | | | S | | - | - | - | - |
| 186 | | | SE | | (91) | (24) | (91) | (24) |
| 187 | | | | B1 | (91) | (24) | (91) | (24) |
| 188 | | | | | | | | |
| 189 | 41181 | Gain from Disposition of NOX Credits | | | | | | |
| 190 | | | SE | | - | - | - | - |
| 191 | | | | B1 | - | - | - | - |
| 192 | | | | | | | | |
| 193 | 4194 | Impact Housing Interest Income | | | | | | |
| 194 | | | SG | | - | - | - | - |
| 195 | | | | B1 | - | - | - | - |
| 196 | | | | | | | | |
| 197 | 421 | (Gain) / Loss on Sale of Utility Plant | | | | | | |
| 198 | | | S | | 80,910 | 80,879 | 59,150 | 80,879 |
| 199 | | | SG | | - | - | - | - |
| 200 | | | SG | | - | - | - | - |
| 201 | | | CN | | - | - | - | - |
| 202 | | | SO | | (477,131) | (130,855) | (110,008) | (30,170) |
| 203 | | | SG | | - | - | (300,141) | (80,690) |
| 204 | | | | B1 | (396,221) | (49,977) | (350,999) | (29,982) |
| 205 | | | | | | | | |
| 206 | **Total Miscellaneous Revenues** | | | **B1** | **(396,311)** | **(50,000)** | **(351,090)** | **(30,006)** |
| 207 | Miscellaneous Expenses | | | | | | | |
| 208 | 4311 | Interest on Customer Deposits | | | | | | |
| 209 | | | S | | - | - | - | - |
| 210 | | | | | - | - | - | - |
| 211 | **Total Miscellaneous Expenses** | | | B1 | **-** | **-** | **-** | **-** |
| 212 | | | | | | | | |
| 213 | **Net Misc Revenue and Expense** | | | **B1** | **(396,311)** | **(50,000)** | **(351,090)** | **(30,006)** |
| 214 | | | | | | | | |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 215 | 500 | Operation Supervision & Engineering | | | | | | |
| 216 | | | SG | | 14,632,688 | 3,933,875 | 15,403,874 | 4,141,202 |
| 217 | | | SG | | - | - | - | - |
| 218 | | | SG | | - | - | (17,293) | (4,649) |
| 219 | | | | B2 | 14,632,688 | 3,933,875 | 15,386,582 | 4,136,553 |
| 220 | | | | | | | | |
| 221 | 501 | Fuel Related-Non NPC | | | | | | |
| 222 | | | S | | - | - | - | - |
| 223 | | | SE | | 22,201,079 | 5,847,569 | 37,773,978 | 9,949,333 |
| 224 | | | SE | | - | - | - | - |
| 225 | | | SE | | - | - | - | - |
| 226 | | | SE | | - | - | - | - |
| 227 | | | | B2 | 22,201,079 | 5,847,569 | 37,773,978 | 9,949,333 |
| 228 | | | | | | | | |
| 229 | 501NPC | Fuel Related-NPC | | | | | | |
| 230 | | | S | | 341,013 | - | - | - |
| 231 | | | SE | | 601,557,043 | 158,444,824 | 709,206,591 | 186,798,767 |
| 232 | | | SE | | - | - | - | - |
| 233 | | | SE | | - | - | - | - |
| 234 | | | SE | | - | - | - | - |
| 235 | | | | B2 | 601,898,056 | 158,444,824 | 709,206,591 | 186,798,767 |
| 236 | | | | | | | | |
| 237 | | Total Fuel Related | | B2 | 624,099,134 | 164,292,393 | 746,980,569 | 196,748,100 |
| 238 | | | | | | | | |
| 239 | 502 | Steam Expenses | | | | | | |
| 240 | | | SG | | 78,328,419 | 21,057,935 | 82,213,626 | 22,102,440 |
| 241 | | | SG | | - | - | - | - |
| 242 | | | SG | | - | - | (5,080) | (1,366) |
| 243 | | | | B2 | 78,328,419 | 21,057,935 | 82,208,546 | 22,101,075 |
| 244 | | | | | | | | |
| 245 | 503 | Steam From Other Sources-Non-NPC | | | | | | |
| 246 | | | SE | | - | - | 539 | 142 |
| 247 | | | | B2 | - | - | 539 | 142 |
| 248 | | | | | | | | |
| 249 | 503NPC | Steam From Other Sources-NPC | | | | | | |
| 250 | | | SE | | 11,210,726 | 2,952,806 | 5,415,246 | 1,426,328 |
| 251 | | | | B2 | 11,210,726 | 2,952,806 | 5,415,246 | 1,426,328 |
| 252 | | | | | | | | |
| 253 | 505 | Electric Expenses | | | | | | |
| 254 | | | SG | | 717,972 | 193,021 | 752,798 | 202,383 |
| 255 | | | SG | | - | - | - | - |
| 256 | | | SG | | - | - | - | - |
| 257 | | | | B2 | 717,972 | 193,021 | 752,798 | 202,383 |
| 258 | | | | | | | | |
| 259 | 506 | Misc. Steam Expense | | | | | | |
| 260 | | | SG | | 35,643,320 | 9,582,406 | 37,516,250 | 10,085,928 |
| 261 | | | SG | | - | - | (6,905,052) | (1,856,365) |
| 262 | | | SE | | - | - | 5,261,096 | 1,385,726 |
| 263 | | | | B2 | 35,643,320 | 9,582,406 | 35,872,294 | 9,615,289 |
| 264 | | | | | | | | |
| 265 | 507 | Rents | | | | | | |
| 266 | | | SG | | (215,297) | (57,881) | (225,712) | (60,681) |
| 267 | | | SG | | - | - | - | - |
| 268 | | | SG | | - | - | - | - |
| 269 | | | | B2 | (215,297) | (57,881) | (225,712) | (60,681) |
| 270 | | | | | | | | |
| 271 | 510 | Maint Supervision & Engineering | | | | | | |
| 272 | | | SG | | 5,000,170 | 1,344,253 | 5,208,721 | 1,400,321 |
| 273 | | | SG | | - | - | - | - |
| 274 | | | SG | | - | - | 1,997,238 | 536,941 |
| 275 | | | | B2 | 5,000,170 | 1,344,253 | 7,205,959 | 1,937,261 |
| 276 | | | | | | | | |
| 277 | | | | | | | | |
| 278 | | | | | | | | |
| 279 | 511 | Maintenance of Structures | | | | | | |
| 280 | | | SG | | 22,653,946 | 6,090,323 | 23,073,365 | 6,203,080 |
| 281 | | | SG | | - | - | - | - |
| 282 | | | SG | | - | - | (12,863) | (3,458) |
| 283 | | | | B2 | 22,653,946 | 6,090,323 | 23,060,502 | 6,199,622 |
| 284 | | | | | | | | |
| 285 | 512 | Maintenance of Boiler Plant | | | | | | |
| 286 | | | SG | | 86,304,858 | 23,202,334 | 87,777,811 | 23,598,325 |
| 287 | | | SG | | - | - | - | - |
| 288 | | | SG | | - | - | (11,077,404) | (2,978,067) |
| 289 | | | | B2 | 86,304,858 | 23,202,334 | 76,700,407 | 20,620,258 |
| 290 | | | | | | | | |
| 291 | 513 | Maintenance of Electric Plant | | | | | | |
| 292 | | | SG | | 36,733,112 | 9,875,388 | 37,427,958 | 10,062,191 |
| 293 | | | SG | | - | - | - | - |
| 294 | | | SG | | - | - | (188) | (51) |
| 295 | | | | B2 | 36,733,112 | 9,875,388 | 37,427,770 | 10,062,140 |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 296 | | | | | | | | |
| 297 | 514 | Maintenance of Misc. Steam Plant | | | | | | |
| 298 | | | SG | | 14,392,219 | 3,869,227 | 14,534,443 | 3,907,462 |
| 299 | | | SG | | - | - | - | - |
| 300 | | | SG | | - | - | (7,590) | (2,041) |
| 301 | | | | B2 | 14,392,219 | 3,869,227 | 14,526,852 | 3,905,422 |
| 302 | | | | | | | | |
| 303 | **Total Steam Power Generation** | | | **B2** | **929,501,268** | **246,336,079** | **1,045,312,352** | **276,893,892** |
| 304 | 517 | Operation Super & Engineering | | | | | | |
| 305 | | | SG | | - | - | - | - |
| 306 | | | | B2 | - | - | - | - |
| 307 | | | | | | | | |
| 308 | 518 | Nuclear Fuel Expense | | | | | | |
| 309 | | | SE | | - | - | - | - |
| 310 | | | | | | | | |
| 311 | | | | B2 | - | - | - | - |
| 312 | | | | | | | | |
| 313 | 519 | Coolants and Water | | | | | | |
| 314 | | | SG | | - | - | - | - |
| 315 | | | | B2 | - | - | - | - |
| 316 | | | | | | | | |
| 317 | 520 | Steam Expenses | | | | | | |
| 318 | | | SG | | - | - | - | - |
| 319 | | | | B2 | - | - | - | - |
| 320 | | | | | | | | |
| 321 | | | | | | | | |
| 322 | | | | | | | | |
| 323 | 523 | Electric Expenses | | | | | | |
| 324 | | | SG | | - | - | - | - |
| 325 | | | | B2 | - | - | - | - |
| 326 | | | | | | | | |
| 327 | 524 | Misc. Nuclear Expenses | | | | | | |
| 328 | | | SG | | - | - | - | - |
| 329 | | | | B2 | - | - | - | - |
| 330 | | | | | | | | |
| 331 | 528 | Maintenance Super & Engineering | | | | | | |
| 332 | | | SG | | - | - | - | - |
| 333 | | | | B2 | - | - | - | - |
| 334 | | | | | | | | |
| 335 | 529 | Maintenance of Structures | | | | | | |
| 336 | | | SG | | - | - | - | - |
| 337 | | | | B2 | - | - | - | - |
| 338 | | | | | | | | |
| 339 | 530 | Maintenance of Reactor Plant | | | | | | |
| 340 | | | SG | | - | - | - | - |
| 341 | | | | B2 | - | - | - | - |
| 342 | | | | | | | | |
| 343 | 531 | Maintenance of Electric Plant | | | | | | |
| 344 | | | SG | | - | - | - | - |
| 345 | | | | B2 | - | - | - | - |
| 346 | | | | | | | | |
| 347 | 532 | Maintenance of Misc Nuclear | | | | | | |
| 348 | | | SG | | - | - | - | - |
| 349 | | | | B2 | - | - | - | - |
| 350 | | | | | | | | |
| 351 | **Total Nuclear Power Generation** | | | **B2** | **-** | **-** | **-** | **-** |
| 352 | | | | | | | | |
| 353 | 535 | Operation Super & Engineering | | | | | | |
| 354 | | | SG | | - | - | 954,852 | 256,704 |
| 355 | | | SG | | - | - | (6,790) | (1,825) |
| 356 | | | SG | | - | - | (2,135,002) | (573,977) |
| 357 | | | SG | | 9,054,832 | 2,434,315 | 9,401,440 | 2,527,498 |
| 358 | | | SG | | 3,422,814 | 920,195 | 3,647,219 | 980,524 |
| 359 | | | | | | | | |
| 360 | | | | B2 | 12,477,645 | 3,354,510 | 11,861,719 | 3,188,923 |
| 361 | | | | | | | | |
| 362 | 536 | Water For Power | | | | | | |
| 363 | | | SG | | - | - | (199) | (53) |
| 364 | | | SG | | 464,604 | 124,905 | 475,251 | 127,767 |
| 365 | | | SG | | - | - | - | - |
| 366 | | | | | | | | |
| 367 | | | | B2 | 464,604 | 124,905 | 475,052 | 127,714 |
| 368 | | | | | | | | |
| 369 | 537 | Hydraulic Expenses | | | | | | |
| 370 | | | SG | | - | - | (513) | (138) |
| 371 | | | SG | | 4,114,974 | 1,106,276 | 4,213,560 | 1,132,780 |
| 372 | | | SG | | 341,210 | 91,731 | 347,622 | 93,455 |
| 373 | | | SG | | - | - | (153) | (41) |
| 374 | | | | B2 | 4,456,184 | 1,198,007 | 4,560,516 | 1,226,056 |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 375 | | | | | | | | |
| 376 | 538 | Electric Expenses | | | | | | |
| 377 | | | DGP | | - | - | - | - |
| 378 | | | SG | | - | - | - | - |
| 379 | | | SG | | - | - | - | - |
| 380 | | | | | | | | |
| 381 | | | | B2 | - | - | - | - |
| 382 | | | | | | | | |
| 383 | 539 | Misc. Hydro Expenses | | | | | | |
| 384 | | | SG | | - | - | - | - |
| 385 | | | SG | | 14,846,760 | 3,991,426 | 15,393,441 | 4,138,397 |
| 386 | | | SG | | 7,957,118 | 2,139,204 | 8,281,240 | 2,226,342 |
| 387 | | | SG | | - | - | (17,487) | (4,701) |
| 388 | | | SG | | - | - | (8,395) | (2,257) |
| 389 | | | | B2 | 22,803,878 | 6,130,630 | 23,648,799 | 6,357,780 |
| 390 | | | | | | | | |
| 391 | 540 | Rents (Hydro Generation) | | | | | | |
| 392 | | | SG | | - | - | - | - |
| 393 | | | SG | | 1,757,400 | 472,462 | 1,790,255 | 481,295 |
| 394 | | | SG | | (133,277) | (35,830) | (135,768) | (36,500) |
| 395 | | | | | | | | |
| 396 | | | | B2 | 1,624,123 | 436,632 | 1,654,488 | 444,795 |
| 397 | | | | | | | | |
| 398 | 541 | Maint Supervision & Engineering | | | | | | |
| 399 | | | SG | | - | - | - | - |
| 400 | | | SG | | 1,559 | 419 | 1,554 | 418 |
| 401 | | | SG | | - | - | - | - |
| 402 | | | | | | | | |
| 403 | | | | B2 | 1,559 | 419 | 1,554 | 418 |
| 404 | | | | | | | | |
| 405 | 542 | Maintenance of Structures | | | | | | |
| 406 | | | SG | | - | - | (85) | (23) |
| 407 | | | SG | | 733,436 | 197,178 | 747,149 | 200,865 |
| 408 | | | SG | | 21,796 | 5,860 | 22,380 | 6,017 |
| 409 | | | SG | | - | - | (28) | (8) |
| 410 | | | | B2 | 755,232 | 203,038 | 769,416 | 206,851 |
| 411 | | | | | | | | |
| 412 | | | | | | | | |
| 413 | | | | | | | | |
| 414 | | | | | | | | |
| 415 | 543 | Maintenance of Dams & Waterways | | | | | | |
| 416 | | | SG | | - | - | (45) | (12) |
| 417 | | | SG | | 930,916 | 250,269 | 955,141 | 256,782 |
| 418 | | | SG | | 505,127 | 135,799 | 520,547 | 139,945 |
| 419 | | | SG | | - | - | 147 | 40 |
| 420 | | | | B2 | 1,436,043 | 386,068 | 1,475,791 | 396,754 |
| 421 | | | | | | | | |
| 422 | 544 | Maintenance of Electric Plant | | | | | | |
| 423 | | | SG | | - | - | (271) | (73) |
| 424 | | | SG | | 1,453,981 | 390,891 | 1,492,729 | 401,308 |
| 425 | | | SG | | 342,943 | 92,197 | 356,433 | 95,824 |
| 426 | | | | | | | | |
| 427 | | | | B2 | 1,796,924 | 483,088 | 1,848,891 | 497,059 |
| 428 | | | | | | | | |
| 429 | 545 | Maintenance of Misc. Hydro Plant | | | | | | |
| 430 | | | SG | | - | - | 3,392 | 912 |
| 431 | | | SG | | - | - | (147) | (40) |
| 432 | | | SG | | (7,385,140) | (1,985,433) | - | - |
| 433 | | | SG | | 3,306,789 | 889,002 | 3,341,854 | 898,429 |
| 434 | | | SG | | 919,889 | 247,304 | 924,173 | 248,456 |
| 435 | | | | | | | | |
| 436 | | | | B2 | (3,158,461) | (849,126) | 4,269,272 | 1,147,758 |
| 437 | | | | | | | | |
| 438 | **Total Hydraulic Power Generation** | | | **B2** | **42,657,730** | **11,468,171** | **50,565,497** | **13,594,108** |
| 439 | | | | | | | | |
| 440 | 546 | Operation Super & Engineering | | | | | | |
| 441 | | | SG | | 504,693 | 135,682 | 526,839 | 141,636 |
| 442 | | | SG | | - | - | - | - |
| 443 | | | SG | | - | - | (976) | (263) |
| 444 | | | | B2 | 504,693 | 135,682 | 525,863 | 141,374 |
| 445 | | | | | | | | |
| 446 | 547 | Fuel-Non-NPC | | | | | | |
| 447 | | | SE | | - | - | - | - |
| 448 | | | SE | | - | - | - | - |
| 449 | | | | B2 | - | - | - | - |
| 450 | | | | | | | | |
| 451 | 547NPC | Fuel-NPC | | | | | | |
| 452 | | | SE | | 621,099,417 | 163,592,113 | 567,999,723 | 149,606,122 |
| 453 | | | SE | | 628,119 | 165,441 | 628,119 | 165,441 |
| 454 | | | | B2 | 621,727,536 | 163,757,555 | 568,627,842 | 149,771,563 |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 455 | | | | | | | | |
| 456 | 548 | Generation Expense | | | | | | |
| 457 | | | SG | | 22,741,307 | 6,113,809 | 23,794,111 | 6,396,846 |
| 458 | | | SG | | 880,908 | 236,825 | 923,954 | 248,397 |
| 459 | | | SG | | - | - | (1,740) | (468) |
| 460 | | | | B2 | 23,622,215 | 6,350,633 | 24,716,326 | 6,644,776 |
| 461 | | | | | | | | |
| 462 | 549 | Miscellaneous Other | | | | | | |
| 463 | | | S | | 32,773 | 32,773 | 34,403 | 34,403 |
| 464 | | | SG | | 4,121,100 | 1,107,923 | 4,340,548 | 1,166,920 |
| 465 | | | SG | | 6,581,094 | 1,769,272 | 6,875,109 | 1,848,315 |
| 466 | | | SG | | - | - | 4,422,359 | 1,188,914 |
| 467 | | | SG | | - | - | - | - |
| 468 | | | | B2 | 10,734,968 | 2,909,968 | 15,672,419 | 4,238,552 |
| 469 | | | | | | | | |
| 470 | | | | | | | | |
| 471 | | | | | | | | |
| 472 | | | | | | | | |
| 473 | 550 | Rents | | | | | | |
| 474 | | | S | | 374,393 | 374,393 | 390,750 | 390,750 |
| 475 | | | SG | | - | - | - | - |
| 476 | | | SG | | 39,881 | 10,722 | 41,623 | 11,190 |
| 477 | | | SG | | 10,639,757 | 2,860,409 | 11,104,613 | 2,985,382 |
| 478 | | | | B2 | 11,054,031 | 3,245,524 | 11,536,987 | 3,387,322 |
| 479 | | | | | | | | |
| 480 | 551 | Maint Supervision & Engineering | | | | | | |
| 481 | | | SG | | - | - | - | - |
| 482 | | | | B2 | - | - | - | - |
| 483 | | | | | | | | |
| 484 | 552 | Maintenance of Structures | | | | | | |
| 485 | | | SG | | 2,391,894 | 643,040 | 2,474,755 | 665,317 |
| 486 | | | SG | | 117,546 | 31,601 | 121,663 | 32,708 |
| 487 | | | SG | | - | - | (1,020) | (274) |
| 488 | | | | B2 | 2,509,439 | 674,642 | 2,595,399 | 697,751 |
| 489 | | | | | | | | |
| 490 | 553 | Maint of Generation & Electric Plant | | | | | | |
| 491 | | | SG | | 3,324,363 | 893,727 | 3,444,144 | 925,929 |
| 492 | | | SG | | 18,210,283 | 4,895,681 | 18,652,230 | 5,014,495 |
| 493 | | | SG | | 292,933 | 78,753 | 301,869 | 81,155 |
| 494 | | | SG | | - | - | 1,760,093 | 473,186 |
| 495 | | | | B2 | 21,827,579 | 5,868,161 | 24,158,336 | 6,494,765 |
| 496 | | | | | | | | |
| 497 | 554 | Maintenance of Misc. Other | | | | | | |
| 498 | | | SG | | 2,200,039 | 591,462 | 2,253,568 | 605,853 |
| 499 | | | SG | | 1,773,101 | 476,683 | 1,815,485 | 488,078 |
| 500 | | | SG | | 128,767 | 34,618 | 133,328 | 35,844 |
| 501 | | | SG | | - | - | (95) | (25) |
| 502 | | | | B2 | 4,101,907 | 1,102,763 | 4,202,287 | 1,129,749 |
| 503 | | | | | | | | |
| 504 | **Total Other Power Generation** | | | **B2** | **696,082,368** | **184,044,927** | **652,035,458** | **172,505,852** |
| 505 | | | | | | | | |
| 506 | | | | | | | | |
| 507 | 555 | Purchased Power-Non NPC | | | | | | |
| 508 | | | S | | (519,795,484) | - | (519,795,484) | - |
| 509 | | | | | (519,795,484) | - | (519,795,484) | - |
| 510 | | | | | | | | |
| 511 | 555NPC | Purchased Power-NPC | | | | | | |
| 512 | | | S | | 13,444,000 | 80,131 | (14,043,485) | (14,043,485) |
| 513 | | | SE | | 20,074,007 | 5,287,317 | 79,995,471 | 21,070,102 |
| 514 | | Seasonal Contracts | SG | | 1,207,781,184 | 324,701,791 | 1,340,263,037 | 360,318,420 |
| 515 | | | DGP | | - | - | - | - |
| 516 | | | | | 1,241,299,192 | 330,069,238 | 1,406,215,023 | 367,345,037 |
| 517 | | | | | | | | |
| 518 | | Total Purchased Power | | B2 | 721,503,708 | 330,069,238 | 886,419,539 | 367,345,037 |
| 519 | | | | | | | | |
| 520 | 556 | System Control & Load Dispatch | | | | | | |
| 521 | | | SG | | 2,506,281 | 673,793 | 2,621,382 | 704,737 |
| 522 | | | | | | | | |
| 523 | | | | B2 | 2,506,281 | 673,793 | 2,621,382 | 704,737 |
| 524 | | | | | | | | |
| 525 | | | | | | | | |
| 526 | | | | | | | | |
| 527 | 557 | Other Expenses | | | | | | |
| 528 | | | S | | 11,472,438 | 7,786,113 | 11,974,134 | 8,126,293 |
| 529 | | | SG | | 33,440,680 | 8,990,245 | 36,460,650 | 9,802,138 |
| 530 | | | SGCT | | - | - | - | - |
| 531 | | | SE | | 6,158 | 1,622 | 6,427 | 1,693 |
| 532 | | | SG | | - | - | - | - |
| 533 | | | TROJP | | - | - | - | - |
| 534 | | | | | | | | |
| 535 | | | | B2 | 44,919,276 | 16,777,980 | 48,441,210 | 17,930,124 |

| | 2020 PROTOCOL<br>Year End<br>FERC<br>ACCT | DESCRIP | FACTOR | Ref | JUNE 2023<br>UNADJUSTED RESULTS<br>TOTAL | <br><br>OREGON | DECEMBER 2025<br>NORMALIZED RESULTS<br>TOTAL | <br><br>OREGON |
|---|---|---|---|---|---|---|---|---|
| 536 | | | | | | | | |
| 537 | Embedded Cost Differentials | | | | | | | |
| 538 | | Company Owned Hydro | DGP | | - | - | - | - |
| 539 | | Company Owned Hydro | SG | | - | - | - | - |
| 540 | | Mid-C Contract | MC | | - | - | - | - |
| 541 | | Mid-C Contract | SG | | - | - | - | - |
| 542 | | Existing QF Contracts | S | | - | - | - | - |
| 543 | | Existing QF Contracts | SG | | - | - | - | - |
| 544 | | | | | | | | |
| 545 | | | | | - | - | - | - |
| 546 | | | | | | | | |
| 547 | | | | | | | | |
| 548 | | | | | | | | |
| 549 | | | | | | | | |
| 550 | 2020 Protocol Adjustment | | | | | | | |
| 551 | | Baseline ECD | S | | (10,164,458) | (11,000,000) | (10,164,458) | (11,000,000) |
| 552 | | | S | | - | - | - | - |
| 553 | 2020 Protocol Adjustment | | | | (10,164,458) | (11,000,000) | (10,164,458) | (11,000,000) |
| 554 | | | | | | | | |
| 555 | **Total Other Power Supply** | | | **B2** | **758,764,807** | **336,521,011** | **927,317,674** | **374,979,897** |
| 556 | | | | | | | | |
| 557 | **Total Production Expense** | | | **B2** | **2,427,006,174** | **778,370,189** | **2,675,230,981** | **837,973,749** |
| 558 | | | | | | | | |
| 559 | | | | | | | | |
| 560 | Summary of Production Expense by Factor | | | | | | | |
| 561 | | | S | | (504,295,324) | (2,726,589) | (531,604,139) | (16,492,039) |
| 562 | | | SG | | 1,654,524,949 | 444,805,086 | 1,800,547,931 | 484,062,134 |
| 563 | | | SE | | 1,276,776,549 | 336,291,692 | 1,406,287,189 | 370,403,654 |
| 564 | | | SNPPH | | - | - | - | - |
| 565 | | | TROJP | | - | - | - | - |
| 566 | | | SGCT | | - | - | - | - |
| 567 | | | DGP | | - | - | - | - |
| 568 | | | DEU | | - | - | - | - |
| 569 | | | DEP | | - | - | - | - |
| 570 | | | SNPPS | | - | - | - | - |
| 571 | | | SNPPO | | - | - | - | - |
| 572 | | | DGU | | - | - | - | - |
| 573 | | | MC | | - | - | - | - |
| 574 | | | SSGCT | | - | - | - | - |
| 575 | | | SSECT | | - | - | - | - |
| 576 | | | SSGC | | - | - | - | - |
| 577 | | | SSGCH | | - | - | - | - |
| 578 | | | SSECH | | - | - | - | - |
| 579 | Total Production Expense by Factor | | | | 2,427,006,174 | 778,370,189 | 2,675,230,981 | 837,973,749 |
| 580 | 560 | Operation Supervision & Engineering | | | | | | |
| 581 | | | SG | | 10,930,041 | 2,938,449 | 11,491,061 | 3,089,275 |
| 582 | | | SG | | - | - | (11,369) | (3,057) |
| 583 | | | | | | | | |
| 584 | | | | B2 | 10,930,041 | 2,938,449 | 11,479,691 | 3,086,218 |
| 585 | | | | | | | | |
| 586 | 561 | Load Dispatching | | | | | | |
| 587 | | | SG | | 18,802,836 | 5,054,984 | 19,453,750 | 5,229,977 |
| 588 | | | SG | | - | - | (3,634) | (977) |
| 589 | | | | | | | | |
| 590 | | | | B2 | 18,802,836 | 5,054,984 | 19,450,116 | 5,229,000 |
| 591 | 562 | Station Expense | | | | | | |
| 592 | | | SG | | 4,696,886 | 1,262,718 | 4,851,408 | 1,304,260 |
| 593 | | | SG | | - | - | (17) | (5) |
| 594 | | | | | | | | |
| 595 | | | | B2 | 4,696,886 | 1,262,718 | 4,851,390 | 1,304,255 |
| 596 | | | | | | | | |
| 597 | 563 | Overhead Line Expense | | | | | | |
| 598 | | | SG | | 1,777,951 | 477,987 | 1,810,588 | 486,761 |
| 599 | | | SG | | - | - | (816) | (219) |
| 600 | | | | | | | | |
| 601 | | | | B2 | 1,777,951 | 477,987 | 1,809,772 | 486,542 |
| 602 | | | | | | | | |
| 603 | 564 | Underground Line Expense | | | | | | |
| 604 | | | SG | | - | - | - | - |
| 605 | | | | | | | | |
| 606 | | | | B2 | - | - | - | - |
| 607 | | | | | | | | |
| 608 | 565 | Transmission of Electricity by Others | | | | | | |
| 609 | | | SG | | - | - | - | - |
| 610 | | | SE | | - | - | - | - |
| 611 | | | | | - | - | - | - |
| 612 | | | | | | | | |
| 613 | 565NPC | Transmission of Electricity by Others-NPC | | | | | | |
| 614 | | | SG | | 141,048,505 | 37,919,702 | 179,009,694 | 48,125,247 |
| 615 | | | SE | | 25,912,615 | 6,825,154 | 12,854,610 | 3,385,791 |
| 616 | | | | | 166,961,120 | 44,744,856 | 191,864,304 | 51,511,038 |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 617 | | | | | | | | |
| 618 | | Total Transmission of Electricity by | | B2 | 166,961,120 | 44,744,856 | 191,864,304 | 51,511,038 |
| 619 | | | | | | | | |
| 620 | 566 | Misc. Transmission Expense | | | | | | |
| 621 | | | SG | | 3,977,554 | 1,069,332 | 3,985,472 | 1,071,461 |
| 622 | | | SG | | - | - | (261) | (70) |
| 623 | | | | | | | | |
| 624 | | | | B2 | 3,977,554 | 1,069,332 | 3,985,211 | 1,071,390 |
| 625 | | | | | | | | |
| 626 | 567 | Rents - Transmission | | | | | | |
| 627 | | | SG | | 2,369,571 | 637,039 | 2,377,390 | 639,141 |
| 628 | | | SG | | - | - | - | - |
| 629 | | | | | | | | |
| 630 | | | | B2 | 2,369,571 | 637,039 | 2,377,390 | 639,141 |
| 631 | | | | | | | | |
| 632 | 568 | Maint Supervision & Engineering | | | | | | |
| 633 | | | SG | | 1,287,165 | 346,044 | 1,374,281 | 369,464 |
| 634 | | | SG | | - | - | (2,424) | (652) |
| 635 | | | | | | | | |
| 636 | | | | B2 | 1,287,165 | 346,044 | 1,371,857 | 368,812 |
| 637 | | | | | | | | |
| 638 | 569 | Maintenance of Structures | | | | | | |
| 639 | | | SG | | 6,226,385 | 1,673,911 | 6,303,051 | 1,694,522 |
| 640 | | | SG | | - | - | (15) | (4) |
| 641 | | | | | | | | |
| 642 | | | | B2 | 6,226,385 | 1,673,911 | 6,303,036 | 1,694,518 |
| 643 | | | | | | | | |
| 644 | 570 | Maintenance of Station Equipment | | | | | | |
| 645 | | | SG | | 14,058,332 | 3,779,464 | 14,314,111 | 3,848,228 |
| 646 | | | SG | | - | - | (1,306) | (351) |
| 647 | | | | | | | | |
| 648 | | | | B2 | 14,058,332 | 3,779,464 | 14,312,804 | 3,847,877 |
| 649 | | | | | | | | |
| 650 | 571 | Maintenance of Overhead Lines | | | | | | |
| 651 | | | SG | | 15,825,442 | 4,254,537 | 15,591,773 | 4,191,717 |
| 652 | | | SG | | - | - | (8,847,498) | (2,378,575) |
| 653 | | | | | | | | |
| 654 | | | | B2 | 15,825,442 | 4,254,537 | 6,744,275 | 1,813,142 |
| 655 | | | | | | | | |
| 656 | 572 | Maintenance of Underground Lines | | | | | | |
| 657 | | | SG | | 165,378 | 44,461 | 165,152 | 44,400 |
| 658 | | | SG | | - | - | (88) | (24) |
| 659 | | | | | | | | |
| 660 | | | | B2 | 165,378 | 44,461 | 165,064 | 44,376 |
| 661 | | | | | | | | |
| 662 | 573 | Maint of Misc. Transmission Plant | | | | | | |
| 663 | | | SG | | 98,296 | 26,426 | 95,077 | 25,561 |
| 664 | | | SG | | - | - | - | - |
| 665 | | | | | | | | |
| 666 | | | | B2 | 98,296 | 26,426 | 95,077 | 25,561 |
| 667 | | | | | | | | |
| 668 | **Total Transmission Expense** | | | **B2** | **247,176,958** | **66,310,208** | **264,809,989** | **71,121,871** |
| 669 | | | | | | | | |
| 670 | Summary of Transmission Expense by Factor | | | | | | | |
| 671 | | SE | | | 25,912,615 | 6,825,154 | 12,854,610 | 3,385,791 |
| 672 | | SG | | | 221,264,343 | 59,485,053 | 251,955,379 | 67,736,080 |
| 673 | | SNPT | | | - | - | - | - |
| 674 | Total Transmission Expense by Factor | | | | 247,176,958 | 66,310,208 | 264,809,989 | 71,121,871 |
| 675 | 580 | Operation Supervision & Engineering | | | | | | |
| 676 | | | S | | 3,512,365 | 1,405,980 | 3,686,010 | 1,480,647 |
| 677 | | | SNPD | | 14,628,141 | 3,656,802 | 15,167,982 | 3,791,754 |
| 678 | | | | B2 | 18,140,506 | 5,062,782 | 18,853,993 | 5,272,401 |
| 679 | | | | | | | | |
| 680 | 581 | Load Dispatching | | | | | | |
| 681 | | | S | | - | - | - | - |
| 682 | | | SNPD | | 16,273,116 | 4,068,020 | 17,139,463 | 4,284,593 |
| 683 | | | | B2 | 16,273,116 | 4,068,020 | 17,139,463 | 4,284,593 |
| 684 | | | | | | | | |
| 685 | 582 | Station Expense | | | | | | |
| 686 | | | S | | 5,218,862 | 1,100,166 | 5,411,421 | 1,136,479 |
| 687 | | | SNPD | | 501 | 125 | 522 | 130 |
| 688 | | | | B2 | 5,219,363 | 1,100,291 | 5,411,943 | 1,136,609 |
| 689 | | | | | | | | |
| 690 | 583 | Overhead Line Expenses | | | | | | |
| 691 | | | S | | 11,094,040 | 2,484,502 | 11,648,858 | 2,661,115 |
| 692 | | | SNPD | | - | - | - | - |
| 693 | | | | B2 | 11,094,040 | 2,484,502 | 11,648,858 | 2,661,115 |
| 694 | | | | | | | | |
| 695 | 584 | Underground Line Expense | | | | | | |
| 696 | | | S | | - | - | - | - |
| 697 | | | SNPD | | - | - | - | - |
| 698 | | | | B2 | - | - | - | - |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 699 | | | | | | | | |
| 700 | 585 | Street Lighting & Signal Systems | | | | | | |
| 701 | | | S | | - | - | - | - |
| 702 | | | SNPD | | 285,897 | 71,470 | 299,996 | 74,994 |
| 703 | | | | B2 | 285,897 | 71,470 | 299,996 | 74,994 |
| 704 | | | | | | | | |
| 705 | 586 | Meter Expenses | | | | | | |
| 706 | | | S | | 2,702,247 | 1,323,961 | 2,828,288 | 1,386,311 |
| 707 | | | SNPD | | - | - | - | - |
| 708 | | | | B2 | 2,702,247 | 1,323,961 | 2,828,288 | 1,386,311 |
| 709 | | | | | | | | |
| 710 | 587 | Customer Installation Expenses | | | | | | |
| 711 | | | S | | 21,049,798 | 7,224,789 | 21,989,321 | 7,555,742 |
| 712 | | | SNPD | | - | - | - | - |
| 713 | | | | B2 | 21,049,798 | 7,224,789 | 21,989,321 | 7,555,742 |
| 714 | | | | | | | | |
| 715 | 588 | Misc. Distribution Expenses | | | | | | |
| 716 | | | S | | 1,942,316 | (292,109) | 2,022,983 | (297,241) |
| 717 | | | SNPD | | 132,294 | 33,071 | 696,791 | 174,187 |
| 718 | | | | B2 | 2,074,610 | (259,038) | 2,719,774 | (123,054) |
| 719 | | | | | | | | |
| 720 | 589 | Rents | | | | | | |
| 721 | | | S | | 2,858,365 | 1,830,561 | 2,933,252 | 1,871,306 |
| 722 | | | SNPD | | 396,486 | 99,115 | 404,913 | 101,222 |
| 723 | | | | B2 | 3,254,851 | 1,929,676 | 3,338,165 | 1,972,528 |
| 724 | | | | | | | | |
| 725 | 590 | Maint Supervision & Engineering | | | | | | |
| 726 | | | S | | (5,277,012) | 990,143 | (4,824,488) | 1,026,674 |
| 727 | | | SNPD | | 3,218,427 | 804,555 | 3,326,967 | 831,689 |
| 728 | | | | B2 | (2,058,586) | 1,794,698 | (1,497,521) | 1,858,363 |
| 729 | | | | | | | | |
| 730 | 591 | Maintenance of Structures | | | | | | |
| 731 | | | S | | 2,065,590 | 689,375 | 1,974,450 | 658,957 |
| 732 | | | SNPD | | 83,550 | 20,886 | 80,142 | 20,034 |
| 733 | | | | B2 | 2,149,140 | 710,261 | 2,054,592 | 678,992 |
| 734 | | | | | | | | |
| 735 | 592 | Maintenance of Station Equipment | | | | | | |
| 736 | | | S | | 9,115,374 | 3,274,403 | 10,181,627 | 4,194,210 |
| 737 | | | SNPD | | 956,139 | 239,019 | 1,155,750 | 288,919 |
| 738 | | | | B2 | 10,071,512 | 3,513,422 | 11,337,377 | 4,483,129 |
| 739 | 593 | Maintenance of Overhead Lines | | | | | | |
| 740 | | | S | | 138,967,405 | 62,571,152 | 147,581,997 | 70,253,525 |
| 741 | | | SNPD | | 3,289,392 | 822,296 | 3,364,661 | 841,112 |
| 742 | | | | B2 | 142,256,797 | 63,393,448 | 150,946,658 | 71,094,637 |
| 743 | | | | | | | | |
| 744 | 594 | Maintenance of Underground Lines | | | | | | |
| 745 | | | S | | 40,345,598 | 9,370,272 | 40,279,160 | 9,437,390 |
| 746 | | | SNPD | | 9,382 | 2,345 | 9,675 | 2,418 |
| 747 | | | | B2 | 40,354,980 | 9,372,617 | 40,288,835 | 9,439,809 |
| 748 | | | | | | | | |
| 749 | 595 | Maintenance of Line Transformers | | | | | | |
| 750 | | | S | | - | - | 438 | - |
| 751 | | | SNPD | | 1,056,734 | 264,167 | 1,087,179 | 271,777 |
| 752 | | | | B2 | 1,056,734 | 264,167 | 1,087,617 | 271,777 |
| 753 | | | | | | | | |
| 754 | 596 | Maint of Street Lighting & Signal Sys. | | | | | | |
| 755 | | | S | | 2,351,219 | 773,084 | 2,358,943 | 789,399 |
| 756 | | | SNPD | | - | - | - | - |
| 757 | | | | B2 | 2,351,219 | 773,084 | 2,358,943 | 789,399 |
| 758 | | | | | | | | |
| 759 | 597 | Maintenance of Meters | | | | | | |
| 760 | | | S | | 589,900 | 172,264 | 607,141 | 178,248 |
| 761 | | | SNPD | | (28,761) | (7,190) | (25,957) | (6,489) |
| 762 | | | | B2 | 561,140 | 165,075 | 581,184 | 171,760 |
| 763 | | | | | | | | |
| 764 | 598 | Maint of Misc. Distribution Plant | | | | | | |
| 765 | | | S | | 2,164,554 | 695,412 | 2,073,499 | 667,194 |
| 766 | | | SNPD | | 3,599,473 | 899,811 | 3,464,047 | 865,957 |
| 767 | | | | B2 | 5,764,027 | 1,595,223 | 5,537,546 | 1,533,150 |
| 768 | | | | | | | | |
| 769 | **Total Distribution Expense** | | | **B2** | **282,601,391** | **104,588,448** | **296,925,033** | **114,542,254** |
| 770 | | | | | | | | |
| 771 | | | | | | | | |
| 772 | Summary of Distribution Expense by Factor | | | | | | | |
| 773 | | S | | | 238,700,620 | 93,613,955 | 250,752,902 | 102,999,957 |
| 774 | | SNPD | | | 43,900,772 | 10,974,493 | 46,172,131 | 11,542,297 |
| 775 | | | | | | | | |
| 776 | Total Distribution Expense by Factor | | | | 282,601,391 | 104,588,448 | 296,925,033 | 114,542,254 |
| 777 | | | | | | | | |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 778 | 901 | Supervision | | | | | | |
| 779 | | | S | | 466 | - | 478 | - |
| 780 | | | CN | | 2,982,177 | 915,693 | 3,117,731 | 957,316 |
| 781 | | | | B2 | 2,982,643 | 915,693 | 3,118,209 | 957,316 |
| 782 | | | | | | | | |
| 783 | 902 | Meter Reading Expense | | | | | | |
| 784 | | | S | | 11,178,872 | 2,002,181 | 11,693,359 | 2,090,906 |
| 785 | | | CN | | 730,563 | 224,323 | 763,937 | 234,571 |
| 786 | | | | B2 | 11,909,435 | 2,226,504 | 12,457,296 | 2,325,477 |
| 787 | | | | | | | | |
| 788 | 903 | Customer Receipts & Collections | | | | | | |
| 789 | | | S | | 3,024,082 | 593,394 | 4,715,140 | 2,180,645 |
| 790 | | | CN | | 38,925,598 | 11,952,312 | 40,610,358 | 12,469,626 |
| 791 | | | | B2 | 41,949,680 | 12,545,706 | 45,325,498 | 14,650,272 |
| 792 | | | | | | | | |
| 793 | 904 | Uncollectible Accounts | | | | | | |
| 794 | | | S | | 24,866,225 | 8,584,525 | 27,211,586 | 10,518,476 |
| 795 | | | SG | | - | - | - | - |
| 796 | | | CN | | (916,184) | (281,319) | (939,334) | (288,428) |
| 797 | | | | B2 | 23,950,041 | 8,303,206 | 26,272,252 | 10,230,048 |
| 798 | | | | | | | | |
| 799 | 905 | Misc. Customer Accounts Expense | | | | | | |
| 800 | | | S | | 252 | (0) | 258 | (0) |
| 801 | | | CN | | 150 | 46 | 154 | 47 |
| 802 | | | | B2 | 402 | 46 | 412 | 47 |
| 803 | | | | | | | | |
| 804 | **Total Customer Accounts Expense** | | | **B2** | **80,792,201** | **23,991,155** | **87,173,667** | **28,163,160** |
| 805 | | | | | | | | |
| 806 | Summary of Customer Accts Exp by Factor | | | | | | | |
| 807 | | S | | | 39,069,897 | 11,180,100 | 43,620,821 | 14,790,027 |
| 808 | | CN | | | 41,722,304 | 12,811,055 | 43,552,846 | 13,373,133 |
| 809 | | SG | | | - | - | - | - |
| 810 | Total Customer Accounts Expense by Factor | | | | 80,792,201 | 23,991,155 | 87,173,667 | 28,163,160 |
| 811 | | | | | | | | |
| 812 | 907 | Supervision | | | | | | |
| 813 | | | S | | - | - | - | - |
| 814 | | | CN | | 1,296 | 398 | 1,285 | 395 |
| 815 | | | | B2 | 1,296 | 398 | 1,285 | 395 |
| 816 | | | | | | | | |
| 817 | 908 | Customer Assistance | | | | | | |
| 818 | | | S | | 150,123,937 | 2,368,113 | 149,199,702 | 2,475,650 |
| 819 | | | CN | | 3,216,804 | 987,737 | 3,362,443 | 1,032,456 |
| 820 | | | | | | | | |
| 821 | | | | | | | | |
| 822 | | | | B2 | 153,340,741 | 3,355,850 | 152,562,145 | 3,508,106 |
| 823 | | | | | | | | |
| 824 | 909 | Informational & Instructional Adv | | | | | | |
| 825 | | | S | | 2,050,555 | 458,592 | 2,458,942 | 816,425 |
| 826 | | | CN | | 3,578,273 | 1,098,728 | 3,164,004 | 971,524 |
| 827 | | | | B2 | 5,628,828 | 1,557,320 | 5,622,946 | 1,787,949 |
| 828 | | | | | | | | |
| 829 | 910 | Misc. Customer Service | | | | | | |
| 830 | | | S | | - | - | - | - |
| 831 | | | CN | | 9,005 | 2,765 | 7,803 | 2,396 |
| 832 | | | | | | | | |
| 833 | | | | B2 | 9,005 | 2,765 | 7,803 | 2,396 |
| 834 | | | | | | | | |
| 835 | **Total Customer Service Expense** | | | **B2** | **158,979,871** | **4,916,333** | **158,194,179** | **5,298,846** |
| 836 | | | | | | | | |
| 837 | | | | | | | | |
| 838 | Summary of Customer Service Exp by Factor | | | | | | | |
| 839 | | S | | | 152,174,492 | 2,826,705 | 151,658,643 | 3,292,075 |
| 840 | | CN | | | 6,805,379 | 2,089,628 | 6,535,536 | 2,006,771 |
| 841 | | | | | | | | |
| 842 | Total Customer Service Expense by Factor | | | B2 | 158,979,871 | 4,916,333 | 158,194,179 | 5,298,846 |
| 843 | | | | | | | | |
| 844 | | | | | | | | |
| 845 | 911 | Supervision | | | | | | |
| 846 | | | S | | - | - | - | - |
| 847 | | | CN | | - | - | - | - |
| 848 | | | | B2 | - | - | - | - |
| 849 | | | | | | | | |
| 850 | 912 | Demonstration & Selling Expense | | | | | | |
| 851 | | | S | | - | - | - | - |
| 852 | | | CN | | - | - | - | - |
| 853 | | | | B2 | - | - | - | - |
| 854 | | | | | | | | |
| 855 | 913 | Advertising Expense | | | | | | |
| 856 | | | S | | - | - | - | - |
| 857 | | | CN | | - | - | - | - |
| 858 | | | | B2 | - | - | - | - |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 859 | | | | | | | | |
| 860 | 916 | Misc. Sales Expense | | | | | | |
| 861 | | | S | | - | - | - | - |
| 862 | | | CN | | - | - | - | - |
| 863 | | | | B2 | - | - | - | - |
| 864 | | | | | | | | |
| 865 | **Total Sales Expense** | | | **B2** | **-** | **-** | **-** | **-** |
| 866 | | | | | | | | |
| 867 | | | | | | | | |
| 868 | Total Sales Expense by Factor | | | | | | | |
| 869 | | S | | | - | - | - | - |
| 870 | | CN | | | - | - | - | - |
| 871 | Total Sales Expense by Factor | | | | - | - | - | - |
| 872 | | | | | | | | |
| 873 | **Total Customer Service Exp Including Sales** | | | **B2** | **158,979,871** | **4,916,333** | **158,194,179** | **5,298,846** |
| 874 | 920 | Administrative & General Salaries | | | | | | |
| 875 | | | S | | (615,775) | (615,850) | 93,155 | 93,075 |
| 876 | | | CN | | - | - | - | - |
| 877 | | | SO | | 81,072,180 | 22,234,423 | 85,386,467 | 23,417,636 |
| 878 | | | | B2 | 80,456,405 | 21,618,573 | 85,479,622 | 23,510,712 |
| 879 | | | | | | | | |
| 880 | 921 | Office Supplies & expenses | | | | | | |
| 881 | | | S | | 536,549 | (4,518) | 544,379 | (4,585) |
| 882 | | | CN | | 130,985 | 40,220 | 132,896 | 40,807 |
| 883 | | | SO | | 16,883,123 | 4,630,275 | 18,469,206 | 5,065,266 |
| 884 | | | | B2 | 17,550,657 | 4,665,977 | 19,146,482 | 5,101,488 |
| 885 | | | | | | | | |
| 886 | 922 | A&G Expenses Transferred | | | | | | |
| 887 | | | S | | - | - | - | - |
| 888 | | | CN | | - | - | - | - |
| 889 | | | SO | | (48,437,529) | (13,284,218) | (51,062,127) | (14,004,026) |
| 890 | | | | B2 | (48,437,529) | (13,284,218) | (51,062,127) | (14,004,026) |
| 891 | | | | | | | | |
| 892 | 923 | Outside Services | | | | | | |
| 893 | | | S | | 3,070,939 | 817,809 | 3,013,143 | 865,859 |
| 894 | | | CN | | - | - | - | - |
| 895 | | | SO | | 49,301,782 | 13,521,243 | 52,198,500 | 14,315,682 |
| 896 | | | | B2 | 52,372,720 | 14,339,052 | 55,211,643 | 15,181,541 |
| 897 | | | | | | | | |
| 898 | 924 | Property Insurance | | | | | | |
| 899 | | | S | | 14,501,986 | 10,486,751 | 19,789,014 | 15,773,778 |
| 900 | | | SG | | - | - | - | - |
| 901 | | | SO | | 5,049,524 | 1,384,855 | 4,804,432 | 1,317,638 |
| 902 | | | | B2 | 19,551,510 | 11,871,606 | 24,593,446 | 17,091,416 |
| 903 | | | | | | | | |
| 904 | 925 | Injuries & Damages | | | | | | |
| 905 | | | S | | (8,898,109) | (8,898,109) | 3,960,968 | 3,960,968 |
| 906 | | | SO | | 465,818,221 | 127,752,817 | 16,101,277 | 4,415,850 |
| 907 | | | | B2 | 456,920,112 | 118,854,708 | 20,062,246 | 8,376,819 |
| 908 | | | | | | | | |
| 909 | 926 | Employee Pensions & Benefits | | | | | | |
| 910 | | | S | | (13,736,530) | (5,733,248) | (13,736,530) | (5,733,248) |
| 911 | | | SG | | - | - | 2,967,013 | 797,657 |
| 912 | | | SO | | 144,270,988 | 39,566,990 | 113,525,375 | 31,134,863 |
| 913 | | | | B2 | 130,534,458 | 33,833,743 | 102,755,859 | 26,199,272 |
| 914 | | | | | | | | |
| 915 | 927 | Franchise Requirements | | | | | | |
| 916 | | | S | | - | - | - | - |
| 917 | | | SO | | - | - | - | - |
| 918 | | | | B2 | - | - | - | - |
| 919 | | | | | | | | |
| 920 | 928 | Regulatory Commission Expense | | | | | | |
| 921 | | | S | | 19,215,001 | 6,788,165 | 20,873,448 | 8,182,327 |
| 922 | | | SE | | - | - | - | - |
| 923 | | | SO | | 1,691,665 | 463,947 | 1,731,980 | 475,004 |
| 924 | | | SG | | 6,382,311 | 1,715,831 | 6,510,573 | 1,750,313 |
| 925 | | | | B2 | 27,288,977 | 8,967,942 | 29,116,001 | 10,407,643 |
| 926 | | | | | | | | |
| 927 | 929 | Duplicate Charges | | | | | | |
| 928 | | | S | | - | - | - | - |
| 929 | | | SO | | (135,237,887) | (37,089,620) | (136,062,198) | (37,315,692) |
| 930 | | | | B2 | (135,237,887) | (37,089,620) | (136,062,198) | (37,315,692) |
| 931 | | | | | | | | |
| 932 | 930 | Misc General Expenses | | | | | | |
| 933 | | | S | | 119,844 | 40 | (795,137) | (907,933) |
| 934 | | | CN | | - | - | - | - |
| 935 | | | SG | | - | - | - | - |
| 936 | | | SO | | 2,719,242 | 745,765 | 1,969,384 | 540,113 |
| 937 | | | | B2 | 2,839,086 | 745,805 | 1,174,247 | (367,820) |

| | 2020 PROTOCOL<br>Year End<br>FERC<br>ACCT | DESCRIP | FACTOR | Ref | JUNE 2023<br>UNADJUSTED RESULTS<br>TOTAL | <br><br>OREGON | DECEMBER 2025<br>NORMALIZED RESULTS<br>TOTAL | <br><br>OREGON |
|---|---|---|---|---|---|---|---|---|
| 938 | | | | | | | | |
| 939 | 931 | Rents | | | | | | |
| 940 | | | S | | 372,803 | 282,800 | 429,409 | 333,350 |
| 941 | | | SO | | (4,051,577) | (1,111,164) | (4,324,191) | (1,185,930) |
| 942 | | | | B2 | (3,678,774) | (828,364) | (3,894,782) | (852,579) |
| 943 | | | | | | | | |
| 944 | 935 | Maintenance of General Plant | | | | | | |
| 945 | | | S | | 658,849 | 283,117 | 664,642 | 287,691 |
| 946 | | | CN | | 35,808 | 10,995 | 35,783 | 10,987 |
| 947 | | | SO | | 29,577,330 | 8,111,720 | 29,672,619 | 8,137,854 |
| 948 | | | | B2 | 30,271,987 | 8,405,832 | 30,373,044 | 8,436,532 |
| 949 | | | | | | | | |
| 950 | **Total Administrative & General Expense** | | | **B2** | **630,431,721** | **172,101,036** | **176,893,481** | **61,765,305** |
| 951 | | | | | | | | |
| 952 | Summary of A&G Expense by Factor | | | | | | | |
| 953 | | S | | | 15,225,557 | 3,406,956 | 34,836,490 | 22,851,284 |
| 954 | | SE | | | - | - | - | - |
| 955 | | SO | | | 608,657,061 | 166,927,034 | 132,410,725 | 36,314,258 |
| 956 | | SG | | | 6,382,311 | 1,715,831 | 9,477,586 | 2,547,969 |
| 957 | | CN | | | 166,793 | 51,215 | 168,680 | 51,794 |
| 958 | Total A&G Expense by Factor | | | | 630,431,721 | 172,101,036 | 176,893,481 | 61,765,305 |
| 959 | | | | | | | | |
| 960 | **Total O&M Expense** | | | **B2** | **3,826,988,315** | **1,150,277,368** | **3,659,227,331** | **1,118,865,185** |
| 961 | 403SP | Steam Depreciation | | | | | | |
| 962 | | | S | | (6,748,935) | - | - | - |
| 963 | | | SG | | 50,674,954 | 13,623,534 | 50,674,954 | 13,623,534 |
| 964 | | | SG | | 37,646,705 | 10,120,999 | 37,646,705 | 10,120,999 |
| 965 | | | SG | | 264,110,600 | 71,003,909 | 333,027,444 | 89,531,621 |
| 966 | | | SG | | - | - | - | - |
| 967 | | | | B3 | 345,683,324 | 94,748,442 | 421,349,103 | 113,276,155 |
| 968 | | | | | | | | |
| 969 | 403NP | Nuclear Depreciation | | | | | | |
| 970 | | | SG | | - | - | - | - |
| 971 | | | | B3 | - | - | - | - |
| 972 | | | | | | | | |
| 973 | 403HP | Hydro Depreciation | | | | | | |
| 974 | | | SG | | 15,346,394 | 4,125,749 | 15,346,394 | 4,125,749 |
| 975 | | | SG | | 1,316,807 | 354,012 | 1,316,807 | 354,012 |
| 976 | | | SG | | 6,840,910 | 1,839,121 | 20,657,435 | 5,553,577 |
| 977 | | | SG | | 7,852,010 | 2,110,947 | 9,365,259 | 2,517,771 |
| 978 | | | SG | | - | - | (11,378,816) | (3,059,099) |
| 979 | | | | B3 | 31,356,121 | 8,429,829 | 35,307,079 | 9,492,011 |
| 980 | | | | | | | | |
| 981 | 403OP | Other Production Depreciation | | | | | | |
| 982 | | | S | | 20,057 | 158 | 61,373 | 61,373 |
| 983 | | | SG | | - | - | - | - |
| 984 | | | SG | | 70,324,552 | 18,906,163 | 68,630,208 | 18,450,653 |
| 985 | | | SG | | 4,283,251 | 1,151,516 | 4,283,251 | 1,151,516 |
| 986 | | | SG | | 143,905,228 | 38,687,707 | 162,327,029 | 43,640,253 |
| 987 | | | | B3 | 218,533,087 | 58,745,544 | 235,301,861 | 63,303,795 |
| 988 | | | | | | | | |
| 989 | 403TP | Transmission Depreciation | | | | | | |
| 990 | | | SG | | 8,251,666 | 2,218,391 | 8,251,666 | 2,218,391 |
| 991 | | | SG | | 10,327,742 | 2,776,526 | 10,327,742 | 2,776,526 |
| 992 | | | SG | | 119,677,406 | 32,174,262 | 175,171,380 | 47,093,349 |
| 993 | | | | B3 | 138,256,814 | 37,169,179 | 193,750,789 | 52,088,266 |
| 994 | | | | | | | | |
| 995 | | | | | | | | |
| 996 | | | | | | | | |
| 997 | 403 | Distribution Depreciation | | | | | | |
| 998 | 360 | Land & Land Rights | S | | 527,771 | 73,474 | 776,301 | 105,224 |
| 999 | 361 | Structures | S | | 2,505,872 | 536,738 | 2,982,636 | 597,644 |
| 1000 | 362 | Station Equipment | S | | 28,350,042 | 6,619,129 | 32,351,083 | 7,130,257 |
| 1001 | 363 | Storage Battery Equipment | S | | - | - | - | - |
| 1002 | 364 | Poles & Towers | S | | 50,494,099 | 15,832,720 | 55,419,647 | 16,461,953 |
| 1003 | 365 | OH Conductors | S | | 21,939,011 | 6,641,320 | 25,024,376 | 7,035,472 |
| 1004 | 366 | UG Conduit | S | | 10,562,254 | 2,050,935 | 12,128,676 | 2,251,044 |
| 1005 | 367 | UG Conductor | S | | 21,317,741 | 4,541,656 | 24,885,594 | 4,997,445 |
| 1006 | 368 | Line Trans | S | | 37,750,189 | 12,032,100 | 42,955,903 | 12,694,581 |
| 1007 | 369 | Services | S | | 22,690,906 | 7,207,686 | 26,013,657 | 7,632,164 |
| 1008 | 370 | Meters | S | | 11,606,860 | 1,778,223 | 12,549,381 | 1,898,629 |
| 1009 | 371 | Inst Cust Prem | S | | 459,676 | 116,012 | 488,167 | 119,651 |
| 1010 | 372 | Leased Property | S | | - | - | - | - |
| 1011 | 373 | Street Lighting | S | | 2,253,019 | 617,732 | 2,455,928 | 643,654 |
| 1012 | | | | B3 | 210,457,441 | 58,047,724 | 238,031,349 | 61,567,717 |

| | 2020 PROTOCOL<br>Year End<br>FERC<br>ACCT | DESCRIP | FACTOR | Ref | JUNE 2023<br>UNADJUSTED RESULTS<br>TOTAL | <br><br>OREGON | DECEMBER 2025<br>NORMALIZED RESULTS<br>TOTAL | <br><br>OREGON |
|---|---|---|---|---|---|---|---|---|
| 1013 | | | | | | | | |
| 1014 | 403GP | General Depreciation | | | | | | |
| 1015 | | | S | | 16,547,470 | 5,055,867 | 18,865,645 | 6,424,180 |
| 1016 | | | SG | | 6,539 | 1,758 | 6,539 | 1,758 |
| 1017 | | | SG | | 34,736 | 9,338 | 34,736 | 9,338 |
| 1018 | | | SE | | 112,428 | 29,613 | 112,819 | 29,716 |
| 1019 | | | CN | | 872,675 | 267,960 | 709,753 | 217,934 |
| 1020 | | | SG | | 11,268,948 | 3,029,562 | 11,241,590 | 3,022,207 |
| 1021 | | | SO | | 20,313,717 | 5,571,131 | 27,854,589 | 7,639,251 |
| 1022 | | | SG | | 9,078 | 2,441 | 9,078 | 2,441 |
| 1023 | | | SG | | - | - | - | - |
| 1024 | | | | B3 | 49,165,591 | 13,967,669 | 58,834,749 | 17,346,823 |
| 1025 | | | | | | | | |
| 1026 | 403GV0 | General Vehicles | | | | | | |
| 1027 | | | SG | | - | - | - | - |
| 1028 | | | | B3 | - | - | - | - |
| 1029 | | | | | | | | |
| 1030 | 403MP | Mining Depreciation | | | | | | |
| 1031 | | | SE | | - | - | - | - |
| 1032 | | | | B3 | - | - | - | - |
| 1033 | | | | | | | | |
| 1034 | 403EP | Experimental Plant Depreciation | | | | | | |
| 1035 | | | SG | | - | - | - | - |
| 1036 | | | SG | | - | - | - | - |
| 1037 | | | | B3 | - | - | - | - |
| 1038 | 4031 | ARO Depreciation | | | | | | |
| 1039 | | | S | | - | - | - | - |
| 1040 | | | | B3 | - | - | - | - |
| 1041 | | | | | | | | |
| 1042 | | | | | | | | |
| 1043 | **Total Depreciation Expense** | | | **B3** | **993,452,379** | **271,108,388** | **1,182,574,929** | **317,074,767** |
| 1044 | | | | | | | | |
| 1045 | Summary | S | | | 227,024,968 | 63,103,749 | 256,958,367 | 68,053,270 |
| 1046 | | DGP | | | - | - | - | - |
| 1047 | | DGU | | | - | - | - | - |
| 1048 | | SG | | | 751,877,526 | 202,135,935 | 896,939,401 | 241,134,597 |
| 1049 | | SO | | | 20,313,717 | 5,571,131 | 27,854,589 | 7,639,251 |
| 1050 | | CN | | | 872,675 | 267,960 | 709,753 | 217,934 |
| 1051 | | SE | | | 112,428 | 29,613 | 112,819 | 29,716 |
| 1052 | | SSGCH | | | - | - | - | - |
| 1053 | | SSGCT | | | - | - | - | - |
| 1054 | Total Depreciation Expense By Factor | | | | 1,000,201,315 | 271,108,388 | 1,182,574,929 | 317,074,767 |
| 1055 | | | | | | | | |
| 1056 | 404GP | Amort of LT Plant - Leasehold Improvements | | | | | | |
| 1057 | | | S | | 384,033 | 145,001 | 420,872 | 139,579 |
| 1058 | | | SG | | - | - | - | - |
| 1059 | | | SO | | 159,654 | 43,786 | 41,363 | 11,344 |
| 1060 | | | SG | | - | - | - | - |
| 1061 | | | CN | | - | - | - | - |
| 1062 | | | SG | | - | - | - | - |
| 1063 | | | | B4 | 543,687 | 188,787 | 462,235 | 150,923 |
| 1064 | | | | | | | | |
| 1065 | 404SP | Amort of LT Plant - Cap Lease Steam | | | | | | |
| 1066 | | | SG | | - | - | - | - |
| 1067 | | | SG | | - | - | - | - |
| 1068 | | | | B4 | - | - | - | - |
| 1069 | | | | | | | | |
| 1070 | 404IP | Amort of LT Plant - Intangible Plant | | | | | | |
| 1071 | | | S | | 2,435,497 | 11,336 | 176,508 | 11,216 |
| 1072 | | | SE | | 1,821 | 480 | 942 | 248 |
| 1073 | | | SG | | 13,211,793 | 3,551,879 | 5,812,970 | 1,562,768 |
| 1074 | | | SO | | 28,903,296 | 7,926,864 | 39,818,038 | 10,920,283 |
| 1075 | | | CN | | 15,686,362 | 4,816,581 | 15,585,835 | 4,785,713 |
| 1076 | | | SG | | 2,697,182 | 725,115 | 2,680,531 | 720,638 |
| 1077 | | | SG | | 324,280 | 87,180 | 314,627 | 84,585 |
| 1078 | | | SG | | 78,646 | 21,143 | 78,646 | 21,143 |
| 1079 | | | SG | | - | - | - | - |
| 1080 | | | SG | | - | - | - | - |
| 1081 | | | SG | | 12,470 | 3,353 | 12,470 | 3,353 |
| 1082 | | | | B4 | 63,351,348 | 17,143,930 | 64,480,568 | 18,109,947 |
| 1083 | | | | | | | | |
| 1084 | 404MP | Amort of LT Plant - Mining Plant | | | | | | |
| 1085 | | | SE | | - | - | - | - |
| 1086 | | | | B4 | - | - | - | - |
| 1087 | | | | | | | | |
| 1088 | 404OP | Amort of LT Plant - Other Plant | | | | | | |
| 1089 | | | S | | 59,650 | 59,650 | 70,641 | 70,641 |
| 1090 | | | | B4 | 59,650 | 59,650 | 70,641 | 70,641 |
| 1091 | | | | | | | | |
| 1092 | | | | | | | | |

| | 2020 PROTOCOL<br>Year End<br>FERC<br>ACCT | DESCRIP | FACTOR | Ref | JUNE 2023<br>UNADJUSTED RESULTS<br>TOTAL | <br><br>OREGON | DECEMBER 2025<br>NORMALIZED RESULTS<br>TOTAL | <br><br>OREGON |
|---|---|---|---|---|---|---|---|---|
| 1093 | 404HP | Amortization of Other Electric Plant | | | | | | |
| 1094 | | | SG | | 313,582 | 84,304 | 313,878 | 84,383 |
| 1095 | | | SG | | - | - | - | - |
| 1096 | | | SG | | - | - | - | - |
| 1097 | | | | B4 | 313,582 | 84,304 | 313,878 | 84,383 |
| 1098 | | | | | | | | |
| 1099 | **Total Amortization of Limited Term Plant** | | | **B4** | **64,268,267** | **17,476,671** | **65,327,322** | **18,415,894** |
| 1100 | | | | | | | | |
| 1101 | | | | | | | | |
| 1102 | 405 | Amortization of Other Electric Plant | | | | | | |
| 1103 | | | S | | - | - | - | - |
| 1104 | | | | | | | | |
| 1105 | | | | B4 | - | - | - | - |
| 1106 | | | | | | | | |
| 1107 | 406 | Amortization of Plant Acquisition Adj | | | | | | |
| 1108 | | | S | | 301,635 | - | 301,635 | - |
| 1109 | | | SG | | - | - | - | - |
| 1110 | | | SG | | - | - | - | - |
| 1111 | | | SG | | 75,351 | 20,258 | 75,351 | 20,258 |
| 1112 | | | SO | | - | - | - | - |
| 1113 | | | | B4 | 376,987 | 20,258 | 376,987 | 20,258 |
| 1114 | 407 | Amort of Prop Losses, Unrec Plant, etc | | | | | | |
| 1115 | | | S | | 11,031,016 | (1,688,853) | 21,573,275 | 8,853,406 |
| 1116 | | | SO | | - | - | - | - |
| 1117 | | | SG-P | | - | - | - | - |
| 1118 | | | SE | | - | - | - | - |
| 1119 | | | SG | | 657,053 | 176,643 | 1,933,332 | 519,760 |
| 1120 | | | TROJP | | - | - | - | - |
| 1121 | | | | B4 | 11,688,069 | (1,512,209) | 23,506,607 | 9,373,166 |
| 1122 | | | | | | | | |
| 1123 | **Total Amortization Expense** | | | **B4** | **76,333,322** | **15,984,719** | **89,210,916** | **27,809,318** |
| 1124 | | | | | | | | |
| 1125 | | | | | | | | |
| 1126 | | | | | | | | |
| 1127 | Summary of Amortization Expense by Factor | | | | | | | |
| 1128 | | S | | | 14,211,832 | (1,472,865) | 22,542,931 | 9,074,842 |
| 1129 | | SE | | | 1,821 | 480 | 942 | 248 |
| 1130 | | TROJP | | | - | - | - | - |
| 1131 | | DGP | | | - | - | - | - |
| 1132 | | DGU | | | - | - | - | - |
| 1133 | | SO | | | 29,062,950 | 7,970,650 | 39,859,402 | 10,931,627 |
| 1134 | | SSGCT | | | - | - | - | - |
| 1135 | | SSGCH | | | - | - | - | - |
| 1136 | | CN | | | 15,686,362 | 4,816,581 | 15,585,835 | 4,785,713 |
| 1137 | | SG | | | 17,370,357 | 4,669,874 | 11,221,805 | 3,016,888 |
| 1138 | Total Amortization Expense by Factor | | | | 76,333,322 | 15,984,719 | 89,210,916 | 27,809,318 |
| 1139 | 408 | Taxes Other Than Income | | | | | | |
| 1140 | | | S | | 36,312,799 | 32,862,927 | 49,158,348 | 45,708,476 |
| 1141 | | | GPS | | 133,792,985 | 36,693,349 | 179,679,000 | 49,277,803 |
| 1142 | | | SO | | 15,434,449 | 4,232,970 | 15,434,449 | 4,232,970 |
| 1143 | | | SE | | 1,205,427 | 317,499 | 1,205,427 | 317,499 |
| 1144 | | | SG | | 1,946,713 | 523,357 | 3,932,236 | 1,057,149 |
| 1145 | | | OPRV-ID | | - | - | - | - |
| 1146 | | | EXCTAX | | - | - | - | - |
| 1147 | | | SG | | - | - | - | - |
| 1148 | | | | | | | | |
| 1149 | | | | | | | | |
| 1150 | | | | | | | | |
| 1151 | **Total Taxes Other Than Income** | | | **B5** | **188,692,373** | **74,630,102** | **249,409,461** | **100,593,896** |
| 1152 | | | | | | | | |
| 1153 | | | | | | | | |
| 1154 | 41140 | Deferred Investment Tax Credit - Fed | | | | | | |
| 1155 | | | DGU | | (910,300) | - | (471,305) | - |
| 1156 | | | | | | | | |
| 1157 | | | | B7 | (910,300) | - | (471,305) | - |
| 1158 | | | | | | | | |
| 1159 | 41141 | Deferred Investment Tax Credit - Idaho | | | | | | |
| 1160 | | | DGU | | - | - | - | - |
| 1161 | | | | | | | | |
| 1162 | | | | B7 | - | - | - | - |
| 1163 | | | | | | | | |
| 1164 | **Total Deferred ITC** | | | **B7** | **(910,300)** | **-** | **(471,305)** | **-** |
| 1165 | | | | | | | | |
| 1166 | | | | | | | | |
| 1167 | 427 | Interest on Long-Term Debt | | | | | | |
| 1168 | | | S | | 469,021,474 | 129,753,787 | 530,639,148 | 142,009,669 |
| 1169 | | | SNP | | - | - | - | - |
| 1170 | | | | B6 | 469,021,474 | 129,753,787 | 530,639,148 | 142,009,669 |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 1171 | | | | | | | | |
| 1172 | 428 | Amortization of Debt Disc & Exp | | | | | | |
| 1173 | | | SNP | | 5,081,412 | 1,328,071 | 5,081,412 | 1,328,071 |
| 1174 | | | | B6 | 5,081,412 | 1,328,071 | 5,081,412 | 1,328,071 |
| 1175 | | | | | | | | |
| 1176 | 429 | Amortization of Premium on Debt | | | | | | |
| 1177 | | | SNP | | (1,586) | (414) | (1,586) | (414) |
| 1178 | | | | B6 | (1,586) | (414) | (1,586) | (414) |
| 1179 | | | | | | | | |
| 1180 | 431 | Other Interest Expense | | | | | | |
| 1181 | | | OTH | | - | - | - | - |
| 1182 | | | SO | | - | - | - | - |
| 1183 | | | SNP | | 31,270,786 | 8,172,894 | 31,270,786 | 8,172,894 |
| 1184 | | | | B6 | 31,270,786 | 8,172,894 | 31,270,786 | 8,172,894 |
| 1185 | | | | | | | | |
| 1186 | 432 | AFUDC - Borrowed | | | | | | |
| 1187 | | | SNP | | (47,517,217) | (12,419,040) | (47,517,217) | (12,419,040) |
| 1188 | | | | | (47,517,217) | (12,419,040) | (47,517,217) | (12,419,040) |
| 1189 | | | | | | | | |
| 1190 | | Total Elec. Interest Deductions for | | B6 | 457,854,870 | 126,835,298 | 519,472,544 | 139,091,179 |
| 1191 | | | | | | | | |
| 1192 | | Non-Regulated Portion of Interest | | | | | | |
| 1193 | | | 427 NUTIL | | - | - | - | - |
| 1194 | | | 428 NUTIL | | - | - | - | - |
| 1195 | | | 429 NUTIL | | - | - | - | - |
| 1196 | | | 431 NUTIL | | - | - | - | - |
| 1197 | | | | | | | | |
| 1198 | | Total Non-Regulated Interest | | | - | - | - | - |
| 1199 | | | | | | | | |
| 1200 | | Total Interest Deductions for Tax | | B6 | 457,854,870 | 126,835,298 | 519,472,544 | 139,091,179 |
| 1201 | | | | | | | | |
| 1202 | | | | | | | | |
| 1203 | 419 | Interest & Dividends | | | | | | |
| 1204 | | | S | | - | - | - | - |
| 1205 | | | SNP | | (103,524,703) | (27,057,087) | (250,960,991) | (65,590,851) |
| 1206 | | Total Operating Deductions for Tax | | B6 | (103,524,703) | (27,057,087) | (250,960,991) | (65,590,851) |
| 1207 | | | | | | | | |
| 1208 | | | | | | | | |
| 1209 | 41010 | Deferred Income Tax - Federal-DR | | | | | | |
| 1210 | | | S | | 85,748,550 | 943,583 | (64,082,460) | (310,307) |
| 1211 | | | TROJD | | - | - | - | - |
| 1212 | | | SG | | - | - | - | - |
| 1213 | | | SO | | (74,383,696) | (20,400,075) | (16,261,605) | (4,459,821) |
| 1214 | | | SNP | | 37,136,073 | 9,705,838 | 89,739,890 | 23,454,306 |
| 1215 | | | SE | | 6,569,304 | 1,730,297 | 15,953 | 4,202 |
| 1216 | | | SG | | 41,768,328 | 11,229,063 | 38,296,680 | 10,295,739 |
| 1217 | | | GPS | | 32,060,721 | 8,792,802 | 11,476,602 | 3,147,512 |
| 1218 | | | DITEXP | | - | - | - | - |
| 1219 | | | BADDEBT | | - | - | - | - |
| 1220 | | | CN | | - | - | - | - |
| 1221 | | | IBT | | - | - | - | - |
| 1222 | | | CIAC | | - | - | - | - |
| 1223 | | | SCHMDEXP | | - | - | - | - |
| 1224 | | | TAXDEPR | | 310,976,044 | 81,771,172 | 343,555,998 | 90,338,073 |
| 1225 | | | SNPD | | 10,833 | 2,708 | - | - |
| 1226 | | | | B7 | 439,886,157 | 93,775,388 | 402,741,058 | 122,469,704 |
| 1227 | | | | | | | | |
| 1228 | | | | | | | | |
| 1229 | | | | | | | | |
| 1230 | 41110 | Deferred Income Tax - Federal-CR | | | | | | |
| 1231 | | | S | | (44,348,109) | (13,059,103) | (104,199,970) | (17,268,513) |
| 1232 | | | SE | | (2,657,283) | (699,905) | (3,658,320) | (963,569) |
| 1233 | | | SG | | - | - | - | - |
| 1234 | | | SNP | | (22,395,044) | (5,853,141) | (53,328,696) | (13,937,921) |
| 1235 | | | SG | | (7,189,068) | (1,932,720) | (54,437,149) | (14,634,969) |
| 1236 | | | GPS | | 392,216 | 107,567 | - | - |
| 1237 | | | SO | | (5,695,937) | (1,562,137) | (11,132,302) | (3,053,086) |
| 1238 | | | SNPD | | (649,785) | (162,436) | - | - |
| 1239 | | | BADDEBT | | (1,347,818) | (524,822) | (0) | (0) |
| 1240 | | | SG | | - | - | - | - |
| 1241 | | | SG | | - | - | - | - |
| 1242 | | | TROJD | | 91,374 | 24,476 | - | - |
| 1243 | | | CN | | - | - | 21,827 | 6,702 |
| 1244 | | | CIAC | | (33,807,601) | (8,451,362) | (36,950,197) | (9,236,961) |
| 1245 | | | SCHMDEXP | | (267,107,007) | (71,617,840) | (268,276,974) | (71,931,536) |
| 1246 | | | TAXDEPR | | - | - | - | - |
| 1247 | | | | B7 | (384,714,062) | (103,731,422) | (531,961,781) | (131,019,852) |
| 1248 | | | | | | | | |
| 1249 | **Total Deferred Income Taxes** | | | **B7** | **55,172,095** | **(9,956,034)** | **(129,220,723)** | **(8,550,148)** |

| | 2020 PROTOCOL<br>Year End<br>FERC<br>ACCT | DESCRIP | FACTOR | Ref | JUNE 2023<br>UNADJUSTED RESULTS<br>TOTAL | <br><br>OREGON | DECEMBER 2025<br>NORMALIZED RESULTS<br>TOTAL | <br><br>OREGON |
|---|---|---|---|---|---|---|---|---|
| 1250 | SCHMAF | Additions - Flow Through | | | | | | |
| 1251 | | | S | | - | - | - | - |
| 1252 | | | SNP | | - | - | - | - |
| 1253 | | | SO | | - | - | - | - |
| 1254 | | | SE | | - | - | - | - |
| 1255 | | | TROJP | | - | - | - | - |
| 1256 | | | SG | | - | - | - | - |
| 1257 | | | | B6 | - | - | - | - |
| 1258 | | | | | | | | |
| 1259 | SCHMAP | Additions - Permanent | | | | | | |
| 1260 | | | S | | - | - | - | - |
| 1261 | | | SE | | 2,679 | 706 | 15,008 | 3,953 |
| 1262 | | | SNP | | - | - | - | - |
| 1263 | | | SO | | 2,637,495 | 723,345 | 1,897,410 | 520,374 |
| 1264 | | | SG | | - | - | - | - |
| 1265 | | | SCHMDEXP | | 153,260 | 41,093 | 131,219 | 35,183 |
| 1266 | | | | B6 | 2,793,433 | 765,143 | 2,043,637 | 559,509 |
| 1267 | | | | | | | | |
| 1268 | SCHMAT | Additions - Temporary | | | | | | |
| 1269 | | | S | | (259,221,280) | (11,508,475) | (378,336) | 21,022,362 |
| 1270 | | | SG | | - | - | - | - |
| 1271 | | | CIAC | | 137,504,173 | 34,373,852 | 150,285,917 | 37,569,085 |
| 1272 | | | SNP | | 91,086,380 | 23,806,223 | 216,901,464 | 56,689,096 |
| 1273 | | | TROJD | | (371,643) | (99,551) | - | - |
| 1274 | | | SG | | - | - | - | - |
| 1275 | | | SE | | 10,807,854 | 2,846,694 | 14,879,342 | 3,919,087 |
| 1276 | | | SG | | (1,552,200) | (417,296) | 41,982,385 | 11,286,610 |
| 1277 | | | GPS | | (1,595,245) | (437,503) | - | - |
| 1278 | | | SO | | 20,519,774 | 5,627,644 | 28,568,586 | 7,835,068 |
| 1279 | | | SNPD | | 2,642,844 | 660,669 | - | - |
| 1280 | | | BADDEBT | | 5,481,922 | 2,134,584 | 0 | 0 |
| 1281 | | | CN | | - | - | (88,778) | (27,260) |
| 1282 | | | SCHMDEXP | | 1,086,392,617 | 291,288,100 | 1,091,151,172 | 292,563,984 |
| 1283 | | | | B6 | 1,091,695,197 | 348,274,940 | 1,543,301,752 | 430,858,032 |
| 1284 | | | | | | | | |
| 1285 | TOTAL SCHEDULE - M ADDITIONS | | | B6 | 1,094,488,630 | 349,040,084 | 1,545,345,389 | 431,417,541 |
| 1286 | | | | | | | | |
| 1287 | SCHMDF | Deductions - Flow Through | | | | | | |
| 1288 | | | S | | - | - | - | - |
| 1289 | | | DGP | | - | - | - | - |
| 1290 | | | DGU | | - | - | - | - |
| 1291 | | | | B6 | - | - | - | - |
| 1292 | SCHMDP | Deductions - Permanent | | | | | | |
| 1293 | | | S | | - | - | - | - |
| 1294 | | | SE | | 3,532,967 | 930,552 | 574,764 | 151,388 |
| 1295 | | | SNP | | 113,981 | 29,790 | 107,935 | 28,210 |
| 1296 | | | SCHMDEXP | | - | - | - | - |
| 1297 | | | SG | | - | - | - | - |
| 1298 | | | SO | | - | - | - | - |
| 1299 | | | | B6 | 3,646,948 | 960,342 | 682,699 | 179,597 |
| 1300 | | | | | | | | |
| 1301 | SCHMDT | Deductions - Temporary | | | | | | |
| 1302 | | | S | | 348,761,317 | 3,837,789 | (260,639,739) | (1,262,073) |
| 1303 | | | BADDEBT | | - | - | - | - |
| 1304 | | | SNP | | 151,041,919 | 39,476,127 | 364,995,118 | 95,394,668 |
| 1305 | | | CN | | - | - | - | - |
| 1306 | | | SG | | - | - | - | - |
| 1307 | | | DGP | | - | - | - | - |
| 1308 | | | SE | | 26,719,047 | 7,037,562 | 64,891 | 17,092 |
| 1309 | | | SG | | 169,882,496 | 45,671,477 | 155,762,417 | 41,875,413 |
| 1310 | | | GPS | | 130,399,159 | 35,762,577 | 46,678,274 | 12,801,734 |
| 1311 | | | SO | | (302,537,538) | (82,972,329) | (66,140,106) | (18,139,232) |
| 1312 | | | TAXDEPR | | 1,264,819,225 | 332,584,303 | 1,397,330,243 | 367,428,084 |
| 1313 | | | SNPD | | 44,060 | 11,014 | (0) | (0) |
| 1314 | | | | B6 | 1,789,129,685 | 381,408,520 | 1,638,051,097 | 498,115,685 |
| 1315 | | | | | | | | |
| 1316 | TOTAL SCHEDULE - M DEDUCTIONS | | | B6 | 1,792,776,633 | 382,368,862 | 1,638,733,796 | 498,295,283 |
| 1317 | | | | | | | | |
| 1318 | **TOTAL SCHEDULE - M ADJUSTMENTS** | | | **B6** | **(698,288,003)** | **(33,328,779)** | **(93,388,408)** | **(66,877,741)** |
| 1319 | | | | | | | | |
| 1320 | | | | | | | | |
| 1321 | | | | | | | | |
| 1322 | 40911 | State Income Taxes | | | | | | |
| 1323 | | | | | (12,421,447) | (4,592,219) | 30,497,656 | 6,189,463 |
| 1324 | | | S | | 9,593,106 | 2,984,000 | 6,828,200 | 219,094 |
| 1325 | | PTC | SG | | - | - | - | - |
| 1326 | | | IBT | | - | - | - | - |
| 1327 | **Total State Tax Expense** | | | | **(2,828,341)** | **(1,608,219)** | **37,325,856** | **6,408,557** |
| 1328 | | | | | | | | |
| 1329 | | | | | | | | |

| | 2020 PROTOCOL<br>Year End<br>FERC<br>ACCT | DESCRIP | FACTOR | Ref | JUNE 2023<br>UNADJUSTED RESULTS<br>TOTAL | <br><br>OREGON | DECEMBER 2025<br>NORMALIZED RESULTS<br>TOTAL | <br><br>OREGON |
|---|---|---|---|---|---|---|---|---|
| 1330 | Calculation of Taxable Income: | | | | | | | |
| 1331 | | Operating Revenues | | | 5,864,088,087 | 1,543,907,367 | 6,213,726,037 | 1,841,023,010 |
| 1332 | | Operating Deductions: | | | | | | |
| 1333 | | O & M Expenses | | | 3,826,988,315 | 1,150,277,368 | 3,659,227,331 | 1,118,865,185 |
| 1334 | | Depreciation Expense | | | 993,452,379 | 271,108,388 | 1,182,574,929 | 317,074,767 |
| 1335 | | Amortization Expense | | | 76,333,322 | 15,984,719 | 89,210,916 | 27,809,318 |
| 1336 | | Taxes Other Than Income | | | 188,692,373 | 74,630,102 | 249,409,461 | 100,593,896 |
| 1337 | | Interest & Dividends (AFUDC-Equity) | | | (103,524,703) | (27,057,087) | (250,960,991) | (65,590,851) |
| 1338 | | Misc Revenue & Expense | | | (396,311) | (50,000) | (351,090) | (30,006) |
| 1339 | | Total Operating Deductions | | | 4,981,545,376 | 1,484,893,490 | 4,929,110,555 | 1,498,722,309 |
| 1340 | | Other Deductions: | | | | | | |
| 1341 | | Interest Deductions | | | 457,854,870 | 126,835,298 | 519,472,544 | 139,091,179 |
| 1342 | | Interest on PCRBS | | | - | - | - | - |
| 1343 | | Schedule M Adjustments | | | (698,288,003) | (33,328,779) | (93,388,408) | (66,877,741) |
| 1344 | | | | | | | | |
| 1345 | | Income Before State Taxes | | | (273,600,162) | (101,150,200) | 671,754,530 | 136,331,781 |
| 1346 | | | | | | | | |
| 1347 | | State Income Taxes | | | (2,828,341) | (1,608,219) | 37,325,856 | 6,408,557 |
| 1348 | | | | | | | | |
| 1349 | Total Taxable Income | | | | (270,771,821) | (99,541,981) | 634,428,675 | 129,923,224 |
| 1350 | | | | | | | | |
| 1351 | Tax Rate | | | | 21.0% | 21.0% | 21.0% | 21.0% |
| 1352 | | | | | | | | |
| 1353 | Federal Income Tax - Calculated | | | | (56,862,082) | (20,903,816) | 133,230,022 | 27,283,877 |
| 1354 | | | | | | | | |
| 1355 | Adjustments to Calculated Tax: | | | | | | | |
| 1356 | 40910 | | SE | | (2,701) | (711) | (15,000) | (3,951) |
| 1357 | 40910 | PTC | SG | | (196,377,610) | (52,794,465) | (244,457,191) | (65,720,255) |
| 1358 | 40910 | | SO | | (38,776) | (10,634) | (33,410) | (9,163) |
| 1359 | 40910 | IRS Settle | S | | - | - | - | - |
| 1360 | **Federal Income Tax Expense** | | | | **(253,281,170)** | **(73,709,627)** | **(111,275,580)** | **(38,449,492)** |
| 1361 | | | | | | | | |
| 1362 | **Total Operating Expenses** | | | | **4,883,222,363** | **1,426,676,697** | **4,976,429,795** | **1,523,722,077** |
| 1363 | 310 | Land and Land Rights | | | | | | |
| 1364 | | | SG | | 2,327,033 | 625,603 | 2,327,033 | 625,603 |
| 1365 | | | SG | | 33,769,530 | 9,078,654 | 33,769,530 | 9,078,654 |
| 1366 | | | SG | | 54,351,537 | 14,611,953 | 54,351,537 | 14,611,953 |
| 1367 | | | S | | - | - | - | - |
| 1368 | | | SG | | 1,266,851 | 340,582 | 1,266,851 | 340,582 |
| 1369 | | | | B8 | 91,714,952 | 24,656,792 | 91,714,952 | 24,656,792 |
| 1370 | | | | | | | | |
| 1371 | 311 | Structures and Improvements | | | | | | |
| 1372 | | | SG | | 225,389,076 | 60,593,953 | 225,389,076 | 60,593,953 |
| 1373 | | | SG | | 311,097,937 | 83,636,058 | 311,097,937 | 83,636,058 |
| 1374 | | | SG | | 471,568,481 | 126,777,211 | 471,568,481 | 126,777,211 |
| 1375 | | | SG | | - | - | - | - |
| 1376 | | | | B8 | 1,008,055,494 | 271,007,222 | 1,008,055,494 | 271,007,222 |
| 1377 | | | | | | | | |
| 1378 | 312 | Boiler Plant Equipment | | | | | | |
| 1379 | | | SG | | 584,581,300 | 157,159,755 | 584,581,300 | 157,159,755 |
| 1380 | | | SG | | 462,513,467 | 124,342,847 | 462,513,467 | 124,342,847 |
| 1381 | | | SG | | 3,398,079,363 | 913,544,993 | 3,507,993,276 | 943,094,422 |
| 1382 | | | SG | | - | - | - | - |
| 1383 | | | | B8 | 4,445,174,129 | 1,195,047,595 | 4,555,088,042 | 1,224,597,024 |
| 1384 | | | | | | | | |
| 1385 | 314 | Turbogenerator Units | | | | | | |
| 1386 | | | SG | | 108,374,641 | 29,135,609 | 108,374,641 | 29,135,609 |
| 1387 | | | SG | | 106,495,684 | 28,630,467 | 106,495,684 | 28,630,467 |
| 1388 | | | SG | | 778,564,077 | 209,310,389 | 778,564,077 | 209,310,389 |
| 1389 | | | SG | | - | - | - | - |
| 1390 | | | | B8 | 993,434,402 | 267,076,465 | 993,434,402 | 267,076,465 |
| 1391 | | | | | | | | |
| 1392 | 315 | Accessory Electric Equipment | | | | | | |
| 1393 | | | SG | | 85,682,834 | 23,035,108 | 85,682,834 | 23,035,108 |
| 1394 | | | SG | | 133,070,911 | 35,774,993 | 133,070,911 | 35,774,993 |
| 1395 | | | SG | | 209,782,111 | 56,398,152 | 209,782,111 | 56,398,152 |
| 1396 | | | SG | | - | - | - | - |
| 1397 | | | | B8 | 428,535,856 | 115,208,253 | 428,535,856 | 115,208,253 |
| 1398 | | | | | | | | |
| 1399 | | | | | | | | |
| 1400 | | | | | | | | |
| 1401 | 316 | Misc Power Plant Equipment | | | | | | |
| 1402 | | | SG | | 2,348,343 | 631,332 | 2,348,343 | 631,332 |
| 1403 | | | SG | | 4,812,938 | 1,293,918 | 4,812,938 | 1,293,918 |
| 1404 | | | SG | | 26,807,198 | 7,206,889 | 26,807,198 | 7,206,889 |
| 1405 | | | SG | | - | - | - | - |
| 1406 | | | | B8 | 33,968,479 | 9,132,139 | 33,968,479 | 9,132,139 |

| | 2020 PROTOCOL<br>Year End<br>FERC<br>ACCT | DESCRIP | FACTOR | Ref | JUNE 2023<br>UNADJUSTED RESULTS<br>TOTAL | <br><br>OREGON | DECEMBER 2025<br>NORMALIZED RESULTS<br>TOTAL | <br><br>OREGON |
|---|---|---|---|---|---|---|---|---|
| 1407 | | | | | | | | |
| 1408 | 317 | Steam Plant ARO | | | | | | |
| 1409 | | | S | | - | - | - | - |
| 1410 | | | | B8 | - | - | - | - |
| 1411 | | | | | | | | |
| 1412 | SP | Unclassified Steam Plant - Account 300 | | | | | | |
| 1413 | | | SG | | 17,789,039 | 4,782,433 | 17,789,039 | 4,782,433 |
| 1414 | | | | B8 | 17,789,039 | 4,782,433 | 17,789,039 | 4,782,433 |
| 1415 | | | | | | | | |
| 1416 | | | | | | | | |
| 1417 | **Total Steam Production Plant** | | | **B8** | **7,018,672,351** | **1,886,910,899** | **7,128,586,264** | **1,916,460,328** |
| 1418 | | | | | | | | |
| 1419 | | | | | | | | |
| 1420 | Summary of Steam Production Plant by Factor | | | | | | | |
| 1421 | | S | | | - | - | - | - |
| 1422 | | DGP | | | - | - | - | - |
| 1423 | | DGU | | | - | - | - | - |
| 1424 | | SG | | | 7,018,672,351 | 1,886,910,899 | 7,128,586,264 | 1,916,460,328 |
| 1425 | | SSGCH | | | - | - | - | - |
| 1426 | Total Steam Production Plant by Factor | | | | 7,018,672,351 | 1,886,910,899 | 7,128,586,264 | 1,916,460,328 |
| 1427 | 320 | Land and Land Rights | | | | | | |
| 1428 | | | SG | | - | - | - | - |
| 1429 | | | SG | | - | - | - | - |
| 1430 | | | | B8 | - | - | - | - |
| 1431 | | | | | | | | |
| 1432 | 321 | Structures and Improvements | | | | | | |
| 1433 | | | SG | | - | - | - | - |
| 1434 | | | SG | B8 | - | - | - | - |
| 1435 | | | | | - | - | - | - |
| 1436 | | | | | | | | |
| 1437 | 322 | Reactor Plant Equipment | | | | | | |
| 1438 | | | SG | | - | - | - | - |
| 1439 | | | SG | | - | - | - | - |
| 1440 | | | | B8 | - | - | - | - |
| 1441 | | | | | | | | |
| 1442 | 323 | Turbogenerator Units | | | | | | |
| 1443 | | | SG | | - | - | - | - |
| 1444 | | | SG | | - | - | - | - |
| 1445 | | | | B8 | - | - | - | - |
| 1446 | | | | | | | | |
| 1447 | 324 | Land and Land Rights | | | | | | |
| 1448 | | | SG | | - | - | - | - |
| 1449 | | | SG | | - | - | - | - |
| 1450 | | | | B8 | - | - | - | - |
| 1451 | | | | | | | | |
| 1452 | 325 | Misc. Power Plant Equipment | | | | | | |
| 1453 | | | SG | | - | - | - | - |
| 1454 | | | SG | | - | - | - | - |
| 1455 | | | | B8 | - | - | - | - |
| 1456 | | | | | | | | |
| 1457 | | | | | | | | |
| 1458 | NP | Unclassified Nuclear Plant - Acct 300 | | | | | | |
| 1459 | | | SG | | - | - | - | - |
| 1460 | | | | B8 | - | - | - | - |
| 1461 | | | | | | | | |
| 1462 | | | | | | | | |
| 1463 | **Total Nuclear Production Plant** | | | **B8** | **-** | **-** | **-** | **-** |
| 1464 | | | | | | | | |
| 1465 | | | | | | | | |
| 1466 | | | | | | | | |
| 1467 | Summary of Nuclear Production Plant by Factor | | | | | | | |
| 1468 | | DGP | | | - | - | - | - |
| 1469 | | DGU | | | - | - | - | - |
| 1470 | | SG | | | - | - | - | - |
| 1471 | | | | | | | | |
| 1472 | Total Nuclear Plant by Factor | | | | - | - | - | - |
| 1473 | | | | | | | | |
| 1474 | 330 | Land and Land Rights | | | | | | |
| 1475 | | | SG | | 9,836,805 | 2,644,542 | 9,836,805 | 2,644,542 |
| 1476 | | | SG | | 5,264,970 | 1,415,443 | 5,264,970 | 1,415,443 |
| 1477 | | | SG | | 22,035,950 | 5,924,179 | 22,035,950 | 5,924,179 |
| 1478 | | | SG | | 1,333,374 | 358,466 | 1,333,374 | 358,466 |
| 1479 | | | | B8 | 38,471,099 | 10,342,631 | 38,471,099 | 10,342,631 |
| 1480 | | | | | | | | |
| 1481 | 331 | Structures and Improvements | | | | | | |
| 1482 | | | SG | | 15,172,569 | 4,079,017 | 15,172,569 | 4,079,017 |
| 1483 | | | SG | | 4,752,295 | 1,277,614 | 4,752,295 | 1,277,614 |
| 1484 | | | SG | | 245,366,398 | 65,964,688 | 245,366,398 | 65,964,688 |
| 1485 | | | SG | | 17,369,258 | 4,669,579 | 17,369,258 | 4,669,579 |
| 1486 | | | | B8 | 282,660,520 | 75,990,898 | 282,660,520 | 75,990,898 |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 1487 | | | | | | | | |
| 1488 | 332 | Reservoirs, Dams & Waterways | | | | | | |
| 1489 | | | SG | | 126,238,846 | 33,938,250 | 126,238,846 | 33,938,250 |
| 1490 | | | SG | | 18,671,362 | 5,019,638 | 18,671,362 | 5,019,638 |
| 1491 | | | SG | | 281,996,011 | 75,812,251 | 382,550,491 | 102,845,475 |
| 1492 | | | SG | | 87,475,205 | 23,516,971 | 117,873,002 | 31,689,163 |
| 1493 | | | SG | | - | - | (1,321,596) | (355,300) |
| 1494 | | | | B8 | 514,381,425 | 138,287,110 | 644,012,105 | 173,137,226 |
| 1495 | | | | | | | | |
| 1496 | 333 | Water Wheel, Turbines, & Generators | | | | | | |
| 1497 | | | SG | | 25,499,649 | 6,855,366 | 25,499,649 | 6,855,366 |
| 1498 | | | SG | | 6,690,812 | 1,798,769 | 6,690,812 | 1,798,769 |
| 1499 | | | SG | | 53,799,268 | 14,463,480 | 53,799,268 | 14,463,480 |
| 1500 | | | SG | | 44,593,709 | 11,988,643 | 44,593,709 | 11,988,643 |
| 1501 | | | | B8 | 130,583,438 | 35,106,257 | 130,583,438 | 35,106,257 |
| 1502 | | | | | | | | |
| 1503 | 334 | Accessory Electric Equipment | | | | | | |
| 1504 | | | SG | | 2,782,502 | 748,052 | 2,782,502 | 748,052 |
| 1505 | | | SG | | 3,335,903 | 896,830 | 3,335,903 | 896,830 |
| 1506 | | | SG | | 55,539,496 | 14,931,325 | 55,539,496 | 14,931,325 |
| 1507 | | | SG | | 11,384,099 | 3,060,519 | 11,384,099 | 3,060,519 |
| 1508 | | | | B8 | 73,042,000 | 19,636,726 | 73,042,000 | 19,636,726 |
| 1509 | | | | | | | | |
| 1510 | | | | | | | | |
| 1511 | | | | | | | | |
| 1512 | 335 | Misc. Power Plant Equipment | | | | | | |
| 1513 | | | SG | | 973,732 | 261,780 | 973,732 | 261,780 |
| 1514 | | | SG | | 150,826 | 40,548 | 150,826 | 40,548 |
| 1515 | | | SG | | 1,497,327 | 402,544 | 1,497,327 | 402,544 |
| 1516 | | | SG | | 61,353 | 16,494 | 61,353 | 16,494 |
| 1517 | | | | B8 | 2,683,238 | 721,366 | 2,683,238 | 721,366 |
| 1518 | | | | | | | | |
| 1519 | 336 | Roads, Railroads & Bridges | | | | | | |
| 1520 | | | SG | | 3,221,794 | 866,152 | 3,221,794 | 866,152 |
| 1521 | | | SG | | 734,401 | 197,437 | 734,401 | 197,437 |
| 1522 | | | SG | | 18,101,409 | 4,866,411 | 18,101,409 | 4,866,411 |
| 1523 | | | SG | | 3,552,346 | 955,018 | 3,552,346 | 955,018 |
| 1524 | | | | B8 | 25,609,949 | 6,885,019 | 25,609,949 | 6,885,019 |
| 1525 | | | | | | | | |
| 1526 | 337 | Hydro Plant ARO | | | | | | |
| 1527 | | | S | | - | - | - | - |
| 1528 | | | | B8 | - | - | - | - |
| 1529 | | | | | | | | |
| 1530 | HP | Unclassified Hydro Plant - Acct 300 | | | | | | |
| 1531 | | | S | | - | - | - | - |
| 1532 | | | SG | | - | - | - | - |
| 1533 | | | SG | | - | - | - | - |
| 1534 | | | SG | | - | - | - | - |
| 1535 | | | | B8 | - | - | - | - |
| 1536 | | | | | | | | |
| 1537 | **Total Hydraulic Production Plant** | | | **B8** | **1,067,431,670** | **286,970,007** | **1,197,062,350** | **321,820,122** |
| 1538 | | | | | | | | |
| 1539 | Summary of Hydraulic Plant by Factor | | | | | | | |
| 1540 | | S | | | - | - | - | - |
| 1541 | | SG | | | 1,067,431,670 | 286,970,007 | 1,197,062,350 | 321,820,122 |
| 1542 | | DGP | | | - | - | - | - |
| 1543 | | DGU | | | - | - | - | - |
| 1544 | Total Hydraulic Plant by Factor | | | | 1,067,431,670 | 286,970,007 | 1,197,062,350 | 321,820,122 |
| 1545 | | | | | | | | |
| 1546 | 340 | Land and Land Rights | | | | | | |
| 1547 | | | S | | 74,986 | 74,986 | 74,986 | 74,986 |
| 1548 | | | SG | | 39,022,504 | 10,490,871 | 39,022,504 | 10,490,871 |
| 1549 | | | SG | | 13,533,305 | 3,638,315 | 13,533,305 | 3,638,315 |
| 1550 | | | SG | | 235,129 | 63,213 | 235,129 | 63,213 |
| 1551 | | | | B8 | 52,865,925 | 14,267,385 | 52,865,925 | 14,267,385 |
| 1552 | | | | | | | | |
| 1553 | 341 | Structures and Improvements | | | | | | |
| 1554 | | | S | | 73,237 | 3,756 | 73,237 | 3,756 |
| 1555 | | | SG | | 171,265,274 | 46,043,225 | 167,732,528 | 45,093,476 |
| 1556 | | | SG | | - | - | - | - |
| 1557 | | | SG | | 100,605,967 | 27,047,066 | 100,605,967 | 27,047,066 |
| 1558 | | | SG | | 4,273,000 | 1,148,760 | 4,273,000 | 1,148,760 |
| 1559 | | | | B8 | 276,217,478 | 74,242,807 | 272,684,733 | 73,293,058 |
| 1560 | | | | | | | | |
| 1561 | 342 | Fuel Holders, Producers & Accessories | | | | | | |
| 1562 | | | SG | | 13,650,230 | 3,669,749 | 13,650,230 | 3,669,749 |
| 1563 | | | SG | | - | - | - | - |
| 1564 | | | SG | | 2,789,123 | 749,832 | 2,789,123 | 749,832 |
| 1565 | | | | B8 | 16,439,353 | 4,419,581 | 16,439,353 | 4,419,581 |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 1566 | | | | | | | | |
| 1567 | 343 | Prime Movers | | | | | | |
| 1568 | | | S | | - | - | 370,052 | 370,052 |
| 1569 | | | SG | | - | - | - | - |
| 1570 | | | SG | | 2,881,792,687 | 774,745,672 | 3,513,661,830 | 944,618,365 |
| 1571 | | | SG | | 1,084,643,002 | 291,597,128 | 927,563,118 | 249,367,526 |
| 1572 | | | SG | | 61,119,971 | 16,431,589 | 61,119,971 | 16,431,589 |
| 1573 | | | | B8 | 4,027,555,661 | 1,082,774,390 | 4,502,714,972 | 1,210,787,532 |
| 1574 | | | | | | | | |
| 1575 | 344 | Generators | | | | | | |
| 1576 | | | S | | 284,866 | - | 284,866 | - |
| 1577 | | | SG | | 165,210,609 | 44,415,479 | 165,210,609 | 44,415,479 |
| 1578 | | | SG | | 411,075,318 | 110,514,134 | 403,144,993 | 108,382,133 |
| 1579 | | | SG | | 17,799,825 | 4,785,333 | 17,799,825 | 4,785,333 |
| 1580 | | | | B8 | 594,370,618 | 159,714,947 | 586,440,293 | 157,582,946 |
| 1581 | | | | | | | | |
| 1582 | 345 | Accessory Electric Plant | | | | | | |
| 1583 | | | S | | 597,074 | 516,566 | 597,074 | 516,566 |
| 1584 | | | SG | | 211,863,593 | 56,957,741 | 199,420,171 | 53,612,432 |
| 1585 | | | SG | | 247,641,485 | 66,576,326 | 247,641,485 | 66,576,326 |
| 1586 | | | SG | | - | - | - | - |
| 1587 | | | SG | | 2,901,493 | 780,042 | 2,901,493 | 780,042 |
| 1588 | | | | B8 | 463,003,645 | 124,830,675 | 450,560,223 | 121,485,366 |
| 1589 | | | | | | | | |
| 1590 | | | | | | | | |
| 1591 | | | | | | | | |
| 1592 | 346 | Misc. Power Plant Equipment | | | | | | |
| 1593 | | | SG | | 12,977,877 | 3,488,993 | 12,318,380 | 3,311,693 |
| 1594 | | | SG | | 11,863,573 | 3,189,422 | 11,863,573 | 3,189,422 |
| 1595 | | | SG | | - | - | - | - |
| 1596 | | | | B8 | 24,841,450 | 6,678,415 | 24,181,953 | 6,501,114 |
| 1597 | | | | | | | | |
| 1598 | 347 | Other Production ARO | | | | | | |
| 1599 | | | S | | - | - | - | - |
| 1600 | | | | B8 | - | - | - | - |
| 1601 | | | | | | | | |
| 1602 | OP | Unclassified Other Prod Plant-Acct 300 | | | | | | |
| 1603 | | | S | | - | - | - | - |
| 1604 | | | SG | | - | - | - | - |
| 1605 | | | | | - | - | - | - |
| 1606 | | | | | | | | |
| 1607 | **Total Other Production Plant** | | | **B8** | **5,455,294,130** | **1,466,928,199** | **5,905,887,451** | **1,588,336,982** |
| 1608 | | | | | | | | |
| 1609 | Summary of Other Production Plant by Factor | | | | | | | |
| 1610 | | S | | | 1,030,163 | 595,308 | 1,400,215 | 965,360 |
| 1611 | | DGU | | | - | - | - | - |
| 1612 | | SG | | | 5,454,263,967 | 1,466,332,892 | 5,904,487,236 | 1,587,371,623 |
| 1613 | | SSGCT | | | - | - | - | - |
| 1614 | Total of Other Production Plant by Factor | | | | 5,455,294,130 | 1,466,928,199 | 5,905,887,451 | 1,588,336,982 |
| 1615 | | | | | | | | |
| 1616 | Experimental Plant | | | | | | | |
| 1617 | 103 | Experimental Plant | | | | | | |
| 1618 | | | SG | | - | - | - | - |
| 1619 | **Total Experimental Production Plant** | | | **B8** | **-** | **-** | **-** | **-** |
| 1620 | | | | | | | | |
| 1621 | **Total Production Plant** | | | **B8** | **13,541,398,150** | **3,640,809,105** | **14,231,536,065** | **3,826,617,433** |
| 1622 | 350 | Land and Land Rights | | | | | | |
| 1623 | | | SG | | 20,408,749 | 5,486,720 | 20,408,749 | 5,486,720 |
| 1624 | | | SG | | 46,464,678 | 12,491,637 | 46,464,678 | 12,491,637 |
| 1625 | | | SG | | 279,952,592 | 75,262,894 | 279,952,592 | 75,262,894 |
| 1626 | | | | B8 | 346,826,019 | 93,241,252 | 346,826,019 | 93,241,252 |
| 1627 | | | | | | | | |
| 1628 | 352 | Structures and Improvements | | | | | | |
| 1629 | | | S | | - | - | - | - |
| 1630 | | | SG | | 6,904,523 | 1,856,223 | 6,904,523 | 1,856,223 |
| 1631 | | | SG | | 17,394,775 | 4,676,439 | 17,394,775 | 4,676,439 |
| 1632 | | | SG | | 362,085,438 | 97,343,618 | 361,819,486 | 97,272,119 |
| 1633 | | | | B8 | 386,384,736 | 103,876,279 | 386,118,784 | 103,804,780 |
| 1634 | | | | | | | | |
| 1635 | 353 | Station Equipment | | | | | | |
| 1636 | | | SG | | 102,223,543 | 27,481,938 | 102,223,543 | 27,481,938 |
| 1637 | | | SG | | 145,969,092 | 39,242,560 | 145,969,092 | 39,242,560 |
| 1638 | | | SG | | 2,479,223,938 | 666,518,457 | 2,476,645,370 | 665,825,231 |
| 1639 | | | | B8 | 2,727,416,573 | 733,242,955 | 2,724,838,005 | 732,549,729 |
| 1640 | | | | | | | | |
| 1641 | 354 | Towers and Fixtures | | | | | | |
| 1642 | | | SG | | 128,106,134 | 34,440,254 | 128,106,134 | 34,440,254 |
| 1643 | | | SG | | 131,173,487 | 35,264,886 | 131,173,487 | 35,264,886 |
| 1644 | | | SG | | 1,266,725,416 | 340,548,450 | 1,266,725,416 | 340,548,450 |
| 1645 | | | | B8 | 1,526,005,036 | 410,253,591 | 1,526,005,036 | 410,253,591 |
| 1646 | | | | | | | | |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 1647 | 355 | Poles and Fixtures | | | | | | |
| 1648 | | | SG | | 58,479,814 | 15,721,805 | 58,479,814 | 15,721,805 |
| 1649 | | | SG | | 112,737,819 | 30,308,612 | 112,737,819 | 30,308,612 |
| 1650 | | | SG | | 1,107,620,922 | 297,774,548 | 4,277,795,479 | 1,150,049,256 |
| 1651 | | | | B8 | 1,278,838,555 | 343,804,966 | 4,449,013,112 | 1,196,079,673 |
| 1652 | | | | | | | | |
| 1653 | 356 | Clearing and Grading | | | | | | |
| 1654 | | | SG | | 156,662,797 | 42,117,472 | 156,662,797 | 42,117,472 |
| 1655 | | | SG | | 156,151,321 | 41,979,966 | 156,151,321 | 41,979,966 |
| 1656 | | | SG | | 1,363,305,469 | 366,513,184 | 1,363,293,697 | 366,510,019 |
| 1657 | | | | B8 | 1,676,119,586 | 450,610,622 | 1,676,107,815 | 450,607,457 |
| 1658 | | | | | | | | |
| 1659 | 357 | Underground Conduit | | | | | | |
| 1660 | | | SG | | 6,371 | 1,713 | 6,371 | 1,713 |
| 1661 | | | SG | | 91,651 | 24,639 | 91,651 | 24,639 |
| 1662 | | | SG | | 3,774,966 | 1,014,868 | 3,774,966 | 1,014,868 |
| 1663 | | | | B8 | 3,872,987 | 1,041,220 | 3,872,987 | 1,041,220 |
| 1664 | | | | | | | | |
| 1665 | 358 | Underground Conductors | | | | | | |
| 1666 | | | SG | | - | - | - | - |
| 1667 | | | SG | | 1,087,552 | 292,379 | 1,087,552 | 292,379 |
| 1668 | | | SG | | 7,993,065 | 2,148,868 | 7,993,065 | 2,148,868 |
| 1669 | | | | B8 | 9,080,617 | 2,441,247 | 9,080,617 | 2,441,247 |
| 1670 | | | | | | | | |
| 1671 | 359 | Roads and Trails | | | | | | |
| 1672 | | | SG | | 1,863,032 | 500,860 | 1,863,032 | 500,860 |
| 1673 | | | SG | | 435,969 | 117,206 | 435,969 | 117,206 |
| 1674 | | | SG | | 9,842,468 | 2,646,065 | 9,842,468 | 2,646,065 |
| 1675 | | | | B8 | 12,141,468 | 3,264,131 | 12,141,468 | 3,264,131 |
| 1676 | | | | | | | | |
| 1677 | TP | Unclassified Trans Plant - Acct 300 | | | | | | |
| 1678 | | | SG | | 124,433,526 | 33,452,905 | 124,433,526 | 33,452,905 |
| 1679 | | | | B8 | 124,433,526 | 33,452,905 | 124,433,526 | 33,452,905 |
| 1680 | | | | | | | | |
| 1681 | TS0 | Unclassified Trans Sub Plant - Acct 300 | | | | | | |
| 1682 | | | SG | | - | - | - | - |
| 1683 | | | | B8 | - | - | - | - |
| 1684 | | | | | | | | |
| 1685 | **Total Transmission Plant** | | | **B8** | **8,091,119,105** | **2,175,229,169** | **11,258,437,370** | **3,026,735,986** |
| 1686 | Summary of Transmission Plant by Factor | | | | | | | |
| 1687 | | DGP | | | - | - | - | - |
| 1688 | | DGU | | | - | - | - | - |
| 1689 | | SG | | | 8,091,119,105 | 2,175,229,169 | 11,258,437,370 | 3,026,735,986 |
| 1690 | Total Transmission Plant by Factor | | | | 8,091,119,105 | 2,175,229,169 | 11,258,437,370 | 3,026,735,986 |
| 1691 | 360 | Land and Land Rights | | | | | | |
| 1692 | | | S | | 77,395,334 | 15,474,248 | 85,343,751 | 16,501,049 |
| 1693 | | | | B8 | 77,395,334 | 15,474,248 | 85,343,751 | 16,501,049 |
| 1694 | | | | | | | | |
| 1695 | 361 | Structures and Improvements | | | | | | |
| 1696 | | | S | | 148,470,211 | 35,033,648 | 163,578,785 | 36,864,239 |
| 1697 | | | | B8 | 148,470,211 | 35,033,648 | 163,578,785 | 36,864,239 |
| 1698 | | | | | | | | |
| 1699 | 362 | Station Equipment | | | | | | |
| 1700 | | | S | | 1,245,973,796 | 306,033,063 | 1,372,829,387 | 321,458,778 |
| 1701 | | | | B8 | 1,245,973,796 | 306,033,063 | 1,372,829,387 | 321,458,778 |
| 1702 | | | | | | | | |
| 1703 | 363 | Storage Battery Equipment | | | | | | |
| 1704 | | | S | | - | - | - | - |
| 1705 | | | | B8 | - | - | - | - |
| 1706 | | | | | | | | |
| 1707 | 364 | Poles, Towers & Fixtures | | | | | | |
| 1708 | | | S | | 1,533,876,966 | 516,891,491 | 1,691,184,218 | 537,021,123 |
| 1709 | | | | B8 | 1,533,876,966 | 516,891,491 | 1,691,184,218 | 537,021,123 |
| 1710 | | | | | | | | |
| 1711 | 365 | Overhead Conductors | | | | | | |
| 1712 | | | S | | 960,820,986 | 325,012,527 | 1,047,879,016 | 326,142,454 |
| 1713 | | | | B8 | 960,820,986 | 325,012,527 | 1,047,879,016 | 326,142,454 |
| 1714 | | | | | | | | |
| 1715 | 366 | Underground Conduit | | | | | | |
| 1716 | | | S | | 487,803,339 | 120,810,576 | 537,892,224 | 127,274,252 |
| 1717 | | | | B8 | 487,803,339 | 120,810,576 | 537,892,224 | 127,274,252 |
| 1718 | | | | | | | | |
| 1719 | | | | | | | | |
| 1720 | | | | | | | | |
| 1721 | | | | | | | | |
| 1722 | 367 | Underground Conductors | | | | | | |
| 1723 | | | S | | 1,111,073,914 | 235,065,979 | 1,225,180,008 | 249,806,557 |
| 1724 | | | | B8 | 1,111,073,914 | 235,065,979 | 1,225,180,008 | 249,806,557 |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 1725 | | | | | | | | |
| 1726 | 368 | Line Transformers | | | | | | |
| 1727 | | | S | | 1,622,032,246 | 532,450,677 | 1,788,599,594 | 553,956,506 |
| 1728 | | | | B8 | 1,622,032,246 | 532,450,677 | 1,788,599,594 | 553,956,506 |
| 1729 | | | | | | | | |
| 1730 | 369 | Services | | | | | | |
| 1731 | | | S | | 1,034,745,809 | 359,517,354 | 1,141,007,446 | 373,239,647 |
| 1732 | | | | B8 | 1,034,745,809 | 359,517,354 | 1,141,007,446 | 373,239,647 |
| 1733 | | | | | | | | |
| 1734 | 370 | Meters | | | | | | |
| 1735 | | | S | | 293,512,897 | 105,898,473 | 323,656,355 | 109,792,499 |
| 1736 | | | | B8 | 293,512,897 | 105,898,473 | 323,656,355 | 109,792,499 |
| 1737 | | | | | | | | |
| 1738 | 371 | Installations on Customers' Premises | | | | | | |
| 1739 | | | S | | 8,872,474 | 2,685,798 | 9,783,668 | 2,803,509 |
| 1740 | | | | B8 | 8,872,474 | 2,685,798 | 9,783,668 | 2,803,509 |
| 1741 | | | | | | | | |
| 1742 | 372 | Leased Property | | | | | | |
| 1743 | | | S | | - | - | - | - |
| 1744 | | | | B8 | - | - | - | - |
| 1745 | | | | | | | | |
| 1746 | 373 | Street Lights | | | | | | |
| 1747 | | | S | | 63,188,232 | 25,130,359 | 69,677,429 | 25,968,508 |
| 1748 | | | | B8 | 63,188,232 | 25,130,359 | 69,677,429 | 25,968,508 |
| 1749 | | | | | | | | |
| 1750 | DP | Unclassified Dist Plant - Acct 300 | | | | | | |
| 1751 | | | S | | 91,005,899 | 24,538,568 | 91,005,899 | 24,538,568 |
| 1752 | | | | B8 | 91,005,899 | 24,538,568 | 91,005,899 | 24,538,568 |
| 1753 | | | | | | | | |
| 1754 | DS0 | Unclassified Dist Sub Plant - Acct 300 | | | | | | |
| 1755 | | | S | | - | - | - | - |
| 1756 | | | | B8 | - | - | - | - |
| 1757 | | | | | | | | |
| 1758 | | | | | | | | |
| 1759 | **Total Distribution Plant** | | | **B8** | **8,678,772,103** | **2,604,542,761** | **9,547,617,780** | **2,705,367,690** |
| 1760 | | | | | | | | |
| 1761 | Summary of Distribution Plant by Factor | | | | | | | |
| 1762 | | S | | | 8,678,772,103 | 2,604,542,761 | 9,547,617,780 | 2,705,367,690 |
| 1763 | | | | | | | | |
| 1764 | Total Distribution Plant by Factor | | | | 8,678,772,103 | 2,604,542,761 | 9,547,617,780 | 2,705,367,690 |
| 1765 | 389 | Land and Land Rights | | | | | | |
| 1766 | | | S | | 16,330,314 | 6,116,556 | 16,330,314 | 6,116,556 |
| 1767 | | | CN | | 1,128,506 | 346,514 | 1,128,506 | 346,514 |
| 1768 | | | SG | | 332 | 89 | 332 | 89 |
| 1769 | | | SG | | 1,228 | 330 | 1,228 | 330 |
| 1770 | | | SO | | 7,611,617 | 2,087,521 | 7,611,617 | 2,087,521 |
| 1771 | | | | B8 | 25,071,997 | 8,551,011 | 25,071,997 | 8,551,011 |
| 1772 | | | | | | | | |
| 1773 | 390 | Structures and Improvements | | | | | | |
| 1774 | | | S | | 150,891,908 | 44,350,073 | 150,891,908 | 44,350,073 |
| 1775 | | | SG | | 335,238 | 90,126 | 335,238 | 90,126 |
| 1776 | | | SG | | 1,356,387 | 364,653 | 1,356,387 | 364,653 |
| 1777 | | | CN | | 8,218,829 | 2,523,635 | 8,218,829 | 2,523,635 |
| 1778 | | | SG | | 10,331,894 | 2,777,643 | 10,331,894 | 2,777,643 |
| 1779 | | | SE | | 940,953 | 247,839 | 940,953 | 247,839 |
| 1780 | | | SO | | 112,996,016 | 30,989,684 | 112,996,016 | 30,989,684 |
| 1781 | | | | B8 | 285,071,225 | 81,343,652 | 285,071,225 | 81,343,652 |
| 1782 | | | | | | | | |
| 1783 | 391 | Office Furniture & Equipment | | | | | | |
| 1784 | | | S | | 7,224,862 | 2,351,456 | 7,224,862 | 2,351,456 |
| 1785 | | | SG | | - | - | - | - |
| 1786 | | | SG | | - | - | - | - |
| 1787 | | | CN | | 2,869,402 | 881,065 | 2,869,402 | 881,065 |
| 1788 | | | SG | | 4,567,536 | 1,227,944 | 4,567,536 | 1,227,944 |
| 1789 | | | SE | | 26,583 | 7,002 | 26,583 | 7,002 |
| 1790 | | | SO | | 80,210,716 | 21,998,162 | 80,210,716 | 21,998,162 |
| 1791 | | | SG | | - | - | - | - |
| 1792 | | | SG | | 8,326 | 2,238 | 8,326 | 2,238 |
| 1793 | | | | B8 | 94,907,425 | 26,467,867 | 94,907,425 | 26,467,867 |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 1794 | | | | | | | | |
| 1795 | 392 | Transportation Equipment | | | | | | |
| 1796 | | | S | | 121,404,641 | 30,555,126 | 121,194,108 | 30,344,593 |
| 1797 | | | SO | | 6,942,712 | 1,904,071 | 6,942,712 | 1,904,071 |
| 1798 | | | SG | | 24,705,632 | 6,641,901 | 24,705,632 | 6,641,901 |
| 1799 | | | CN | | - | - | - | - |
| 1800 | | | SG | | 667,672 | 179,498 | 667,672 | 179,498 |
| 1801 | | | SE | | 327,360 | 86,224 | 327,360 | 86,224 |
| 1802 | | | SG | | 70,616 | 18,984 | 70,616 | 18,984 |
| 1803 | | | SG | | - | - | - | - |
| 1804 | | | SG | | 44,655 | 12,005 | 44,655 | 12,005 |
| 1805 | | | | B8 | 154,163,287 | 39,397,809 | 153,952,754 | 39,187,276 |
| 1806 | | | | | | | | |
| 1807 | 393 | Stores Equipment | | | | | | |
| 1808 | | | S | | 10,705,594 | 3,157,311 | 10,546,743 | 2,998,461 |
| 1809 | | | SG | | - | - | - | - |
| 1810 | | | SG | | - | - | - | - |
| 1811 | | | SO | | 242,940 | 66,627 | 242,940 | 66,627 |
| 1812 | | | SG | | 6,911,513 | 1,858,102 | 6,911,513 | 1,858,102 |
| 1813 | | | SG | | 53,971 | 14,510 | 53,971 | 14,510 |
| 1814 | | | | B8 | 17,914,017 | 5,096,550 | 17,755,167 | 4,937,700 |
| 1815 | | | | | | | | |
| 1816 | 394 | Tools, Shop & Garage Equipment | | | | | | |
| 1817 | | | S | | 38,782,731 | 10,911,877 | 38,782,731 | 10,911,877 |
| 1818 | | | SG | | 23,979 | 6,446 | 23,979 | 6,446 |
| 1819 | | | SG | | 22,944,395 | 6,168,407 | 22,944,395 | 6,168,407 |
| 1820 | | | SO | | 1,802,346 | 494,302 | 1,802,346 | 494,302 |
| 1821 | | | SE | | 125,691 | 33,106 | 125,691 | 33,106 |
| 1822 | | | SG | | - | - | - | - |
| 1823 | | | SG | | - | - | - | - |
| 1824 | | | SG | | 89,913 | 24,172 | 89,913 | 24,172 |
| 1825 | | | | B8 | 63,769,055 | 17,638,311 | 63,769,055 | 17,638,311 |
| 1826 | | | | | | | | |
| 1827 | 395 | Laboratory Equipment | | | | | | |
| 1828 | | | S | | 28,155,412 | 10,593,738 | 27,882,938 | 10,321,264 |
| 1829 | | | SG | | - | - | - | - |
| 1830 | | | SG | | - | - | - | - |
| 1831 | | | SO | | 5,070,769 | 1,390,682 | 5,070,769 | 1,390,682 |
| 1832 | | | SE | | 1,326,848 | 349,480 | 1,326,848 | 349,480 |
| 1833 | | | SG | | 7,511,378 | 2,019,371 | 7,422,750 | 1,995,544 |
| 1834 | | | SG | | - | - | - | - |
| 1835 | | | SG | | 14,022 | 3,770 | 14,022 | 3,770 |
| 1836 | | | | B8 | 42,078,428 | 14,357,041 | 41,717,326 | 14,060,740 |
| 1837 | | | | | | | | |
| 1838 | 396 | Power Operated Equipment | | | | | | |
| 1839 | | | S | | 183,513,742 | 52,727,762 | 183,451,936 | 52,665,956 |
| 1840 | | | SG | | 262,000 | 70,436 | 262,000 | 70,436 |
| 1841 | | | SG | | 47,251,389 | 12,703,138 | 47,251,389 | 12,703,138 |
| 1842 | | | SO | | 4,663,667 | 1,279,032 | 4,663,667 | 1,279,032 |
| 1843 | | | SG | | 739,649 | 198,848 | 739,649 | 198,848 |
| 1844 | | | SE | | 236,686 | 62,341 | 236,686 | 62,341 |
| 1845 | | | SG | | - | - | - | - |
| 1846 | | | SG | | - | - | - | - |
| 1847 | | | | B8 | 236,667,133 | 67,041,558 | 236,605,326 | 66,979,751 |
| 1848 | 397 | Communication Equipment | | | | | | |
| 1849 | | | S | | 205,678,174 | 64,283,709 | 305,897,824 | 124,669,936 |
| 1850 | | | SG | | - | - | - | - |
| 1851 | | | SG | | 139,259 | 37,439 | 139,259 | 37,439 |
| 1852 | | | SO | | 95,836,464 | 26,283,597 | 161,444,092 | 44,276,794 |
| 1853 | | | CN | | 3,458,622 | 1,061,988 | 1,533,847 | 470,976 |
| 1854 | | | SG | | 206,696,110 | 55,568,507 | 195,826,707 | 52,646,359 |
| 1855 | | | SE | | 361,776 | 95,289 | 161,042 | 42,417 |
| 1856 | | | SG | | - | - | - | - |
| 1857 | | | SG | | 16,633 | 4,472 | 16,633 | 4,472 |
| 1858 | | | | B8 | 512,187,037 | 147,335,000 | 665,019,403 | 222,148,393 |
| 1859 | | | | | | | | |
| 1860 | 398 | Misc. Equipment | | | | | | |
| 1861 | | | S | | 3,742,268 | 1,374,243 | 3,742,268 | 1,374,243 |
| 1862 | | | SG | | - | - | - | - |
| 1863 | | | SG | | - | - | - | - |
| 1864 | | | CN | | 70,861 | 21,758 | 70,861 | 21,758 |
| 1865 | | | SO | | 1,574,970 | 431,943 | 1,574,970 | 431,943 |
| 1866 | | | SE | | 3,966 | 1,045 | 3,966 | 1,045 |
| 1867 | | | SG | | 3,113,773 | 837,112 | 3,113,773 | 837,112 |
| 1868 | | | SG | | - | - | - | - |
| 1869 | | | | B8 | 8,505,838 | 2,666,100 | 8,505,838 | 2,666,100 |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 1870 | | | | | | | | |
| 1871 | 399 | Coal Mine | | | | | | |
| 1872 | | | SE | | 1,822,901 | 480,136 | 44,290,377 | 11,665,695 |
| 1873 | MP | | SE | | - | - | - | - |
| 1874 | | | | B8 | 1,822,901 | 480,136 | 44,290,377 | 11,665,695 |
| 1875 | | | | | | | | |
| 1876 | 399L | WIDCO Capital Lease | | | | | | |
| 1877 | | | SE | | - | - | - | - |
| 1878 | | | | | - | - | - | - |
| 1879 | | | | | | | | |
| 1880 | | Remove Capital Leases | | | - | - | - | - |
| 1881 | | | | | - | - | - | - |
| 1882 | | | | | | | | |
| 1883 | 1011390 | General Capital Leases | | | | | | |
| 1884 | | | S | | 691,142 | 691,142 | 691,142 | 691,142 |
| 1885 | | | SG | | 8,058,124 | 2,166,359 | 8,058,124 | 2,166,359 |
| 1886 | | | SO | | - | - | - | - |
| 1887 | | | | B9 | 8,749,266 | 2,857,500 | 8,749,266 | 2,857,500 |
| 1888 | | | | | | | | |
| 1889 | | Remove Capital Leases | | | (8,749,266) | (2,857,500) | (8,749,266) | (2,857,500) |
| 1890 | | | | | - | - | - | - |
| 1891 | | | | | | | | |
| 1892 | 1011346 | General Gas Line Capital Leases | | | | | | |
| 1893 | | | SG | | - | - | - | - |
| 1894 | | | | B9 | - | - | - | - |
| 1895 | | | | | | | | |
| 1896 | | Remove Capital Leases | | | - | - | - | - |
| 1897 | | | | | - | - | - | - |
| 1898 | | | | | | | | |
| 1899 | GP | Unclassified Gen Plant - Acct 300 | | | | | | |
| 1900 | | | S | | - | - | - | - |
| 1901 | | | SO | | 65,411,605 | 17,939,437 | 65,411,605 | 17,939,437 |
| 1902 | | | CN | | - | - | - | - |
| 1903 | | | SG | | - | - | - | - |
| 1904 | | | SG | | - | - | - | - |
| 1905 | | | SG | | - | - | - | - |
| 1906 | | | | B8 | 65,411,605 | 17,939,437 | 65,411,605 | 17,939,437 |
| 1907 | | | | | | | | |
| 1908 | 399G | Unclassified Gen Plant - Acct 300 | | | | | | |
| 1909 | | | S | | - | - | - | - |
| 1910 | | | SO | | - | - | - | - |
| 1911 | | | SG | | - | - | - | - |
| 1912 | | | SG | | - | - | - | - |
| 1913 | | | SG | | - | - | - | - |
| 1914 | | | | B8 | - | - | - | - |
| 1915 | | | | | | | | |
| 1916 | **Total General Plant** | | | **B8** | **1,507,569,947** | **428,314,471** | **1,702,077,498** | **513,585,933** |
| 1917 | | | | | | | | |
| 1918 | Summary of General Plant by Factor | | | | | | | |
| 1919 | | S | | | 767,120,788 | 227,112,993 | 866,636,774 | 286,795,556 |
| 1920 | | DGP | | | - | - | - | - |
| 1921 | | DGU | | | - | - | - | - |
| 1922 | | SG | | | 345,915,622 | 92,996,499 | 334,957,591 | 90,050,525 |
| 1923 | | SO | | | 382,363,821 | 104,865,059 | 447,971,449 | 122,858,256 |
| 1924 | | SE | | | 5,172,762 | 1,362,460 | 47,439,505 | 12,495,148 |
| 1925 | | CN | | | 15,746,220 | 4,834,960 | 13,821,444 | 4,243,948 |
| 1926 | | DEU | | | - | - | - | - |
| 1927 | | SSGCT | | | - | - | - | - |
| 1928 | | SSGCH | | | - | - | - | - |
| 1929 | | Less Capital Leases | | | (8,749,266) | (2,857,500) | (8,749,266) | (2,857,500) |
| 1930 | Total General Plant by Factor | | | | 1,507,569,947 | 428,314,471 | 1,702,077,498 | 513,585,933 |
| 1931 | 301 | Organization | | | | | | |
| 1932 | | | S | | - | - | - | - |
| 1933 | | | SO | | - | - | - | - |
| 1934 | | | SG | | - | - | - | - |
| 1935 | | | | B8 | - | - | - | - |
| 1936 | 302 | Franchise & Consent | | | | | | |
| 1937 | | | S | | 1,000,000 | - | 1,000,000 | - |
| 1938 | | | SG | | 13,121,054 | 3,527,485 | 16,248,726 | 4,368,333 |
| 1939 | | | SG | | 103,455,075 | 27,813,025 | 103,371,094 | 27,790,447 |
| 1940 | | | SG | | 10,024,217 | 2,694,926 | 9,755,649 | 2,622,724 |
| 1941 | | | SG | | - | - | - | - |
| 1942 | | | SG | | 477,596 | 128,398 | 477,596 | 128,398 |
| 1943 | | | | B8 | 128,077,942 | 34,163,834 | 130,853,065 | 34,909,902 |

| | 2020 PROTOCOL<br>Year End<br>FERC<br>ACCT | DESCRIP | FACTOR | Ref | JUNE 2023<br>UNADJUSTED RESULTS<br>TOTAL | <br><br>OREGON | DECEMBER 2025<br>NORMALIZED RESULTS<br>TOTAL | <br><br>OREGON |
|---|---|---|---|---|---|---|---|---|
| 1944 | | | | | | | | |
| 1945 | 303 | Miscellaneous Intangible Plant | | | | | | |
| 1946 | | | S | | 23,339,968 | 4,613,651 | 23,279,307 | 4,606,407 |
| 1947 | | | SG | | 194,784,035 | 52,366,046 | 194,784,035 | 52,366,046 |
| 1948 | | | SO | | 489,268,951 | 134,184,289 | 542,249,180 | 148,714,363 |
| 1949 | | | SE | | 9,106 | 2,398 | 4,710 | 1,241 |
| 1950 | | | CN | | 231,939,839 | 71,218,359 | 229,473,811 | 70,461,152 |
| 1951 | | | SG | | - | - | - | - |
| 1952 | | | SG | | - | - | - | - |
| 1953 | | | | B8 | 939,341,899 | 262,384,743 | 989,791,043 | 276,149,209 |
| 1954 | 303 | Less Non-Regulated Plant | | | | | | |
| 1955 | | | S | | - | - | - | - |
| 1956 | | | | | 939,341,899 | 262,384,743 | 989,791,043 | 276,149,209 |
| 1957 | IP | Unclassified Intangible Plant - Acct 300 | | | | | | |
| 1958 | | | S | | - | - | - | - |
| 1959 | | | SG | | - | - | - | - |
| 1960 | | | SG | | - | - | - | - |
| 1961 | | | SO | | - | - | - | - |
| 1962 | | | | | - | - | - | - |
| 1963 | | | | | | | | |
| 1964 | **Total Intangible Plant** | | | **B8** | **1,067,419,842** | **296,548,577** | **1,120,644,109** | **311,059,111** |
| 1965 | | | | | | | | |
| 1966 | Summary of Intangible Plant by Factor | | | | | | | |
| 1967 | | S | | | 24,339,968 | 4,613,651 | 24,279,307 | 4,606,407 |
| 1968 | | DGP | | | - | - | - | - |
| 1969 | | DGU | | | - | - | - | - |
| 1970 | | SG | | | 321,861,977 | 86,529,880 | 324,637,101 | 87,275,948 |
| 1971 | | SO | | | 489,268,951 | 134,184,289 | 542,249,180 | 148,714,363 |
| 1972 | | CN | | | 231,939,839 | 71,218,359 | 229,473,811 | 70,461,152 |
| 1973 | | SSGCT | | | - | - | - | - |
| 1974 | | SSGCH | | | - | - | - | - |
| 1975 | | SE | | | 9,106 | 2,398 | 4,710 | 1,241 |
| 1976 | Total Intangible Plant by Factor | | | | 1,067,419,842 | 296,548,577 | 1,120,644,109 | 311,059,111 |
| 1977 | Summary of Unclassified Plant (Account 106) | | | | | | | |
| 1978 | | DP | | | 91,005,899 | 24,538,568 | 91,005,899 | 24,538,568 |
| 1979 | | DS0 | | | - | - | - | - |
| 1980 | | GP | | | 65,411,605 | 17,939,437 | 65,411,605 | 17,939,437 |
| 1981 | | HP | | | - | - | - | - |
| 1982 | | NP | | | - | - | - | - |
| 1983 | | OP | | | - | - | - | - |
| 1984 | | TP | | | 124,433,526 | 33,452,905 | 124,433,526 | 33,452,905 |
| 1985 | | TS0 | | | - | - | - | - |
| 1986 | | IP | | | - | - | - | - |
| 1987 | | MP | | | - | - | - | - |
| 1988 | | SP | | | 17,789,039 | 4,782,433 | 17,789,039 | 4,782,433 |
| 1989 | Total Unclassified Plant by Factor | | | | 298,640,069 | 80,713,343 | 298,640,069 | 80,713,343 |
| 1990 | | | | | | | | |
| 1991 | **Total Electric Plant In Service** | | | **B8** | **32,886,279,146** | **9,145,444,083** | **37,860,312,821** | **10,383,366,153** |
| 1992 | Summary of Electric Plant by Factor | | | | | | | |
| 1993 | | S | | | 9,471,263,022 | 2,836,864,713 | 10,439,934,076 | 2,997,735,013 |
| 1994 | | SE | | | 5,181,868 | 1,364,858 | 47,444,215 | 12,496,388 |
| 1995 | | DGU | | | - | - | - | - |
| 1996 | | DGP | | | - | - | - | - |
| 1997 | | SG | | | 22,299,264,691 | 5,994,969,344 | 26,148,167,911 | 7,029,714,532 |
| 1998 | | SO | | | 871,632,772 | 239,049,348 | 990,220,629 | 271,572,620 |
| 1999 | | CN | | | 247,686,058 | 76,053,319 | 243,295,255 | 74,705,100 |
| 2000 | | DEU | | | - | - | - | - |
| 2001 | | SSGCH | | | - | - | - | - |
| 2002 | | SSGCT | | | - | - | - | - |
| 2003 | | Less Capital Leases | | | (8,749,266) | (2,857,500) | (8,749,266) | (2,857,500) |
| 2004 | | | | | 32,886,279,146 | 9,145,444,083 | 37,860,312,821 | 10,383,366,153 |
| 2005 | 105 | Plant Held For Future Use | | | | | | |
| 2006 | | | S | | 12,062,430 | 6,893,577 | - | - |
| 2007 | | | SG | | - | - | - | - |
| 2008 | | | SG | | 1,517,970 | 408,094 | 1,517,970 | 408,094 |
| 2009 | | | SG | | - | - | - | - |
| 2010 | | | SE | | - | - | - | - |
| 2011 | | | SG | | 594,174 | 159,739 | (1,517,970) | (408,094) |
| 2012 | | | | | | | | |
| 2013 | | | | | | | | |
| 2014 | **Total Plant Held For Future Use** | | | **B10** | **14,174,575** | **7,461,409** | **-** | **-** |
| 2015 | | | | | | | | |
| 2016 | 114 | Electric Plant Acquisition Adjustments | | | | | | |
| 2017 | | | S | | 11,763,784 | - | 11,763,784 | - |
| 2018 | | | SG | | 144,704,699 | 38,902,639 | 144,704,699 | 38,902,639 |
| 2019 | | | SG | | - | - | - | - |
| 2020 | **Total Electric Plant Acquisition Adjustment** | | | **B15** | **156,468,483** | **38,902,639** | **156,468,483** | **38,902,639** |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 2021 | | | | | | | | |
| 2022 | 115 | Accum Provision for Asset Acquisition Adjustments | | | | | | |
| 2023 | | | S | | (2,500,812) | - | (2,500,812) | - |
| 2024 | | | SG | | (142,013,501) | (38,179,133) | (142,088,852) | (38,199,390) |
| 2025 | | | SG | | - | - | - | - |
| 2026 | | | | B15 | (144,514,313) | (38,179,133) | (144,589,665) | (38,199,390) |
| 2027 | | | | | | | | |
| 2028 | 128 | Pensions | | | | | | |
| 2029 | | | SO | | 104,951,393 | 28,783,408 | - | - |
| 2030 | **Total Pensions** | | | **B15** | **104,951,393** | **28,783,408** | **-** | **-** |
| 2031 | | | | | | | | |
| 2032 | 124 | Weatherization | | | | | | |
| 2033 | | | S | | 516,505 | - | 516,505 | - |
| 2034 | | | SO | | - | - | - | - |
| 2035 | | | | B16 | 516,505 | - | 516,505 | - |
| 2036 | | | | | | | | |
| 2037 | 182W | Weatherization | | | | | | |
| 2038 | | | S | | 224,013,752 | - | 224,013,752 | - |
| 2039 | | | SG | | - | - | - | - |
| 2040 | | | SGCT | | - | - | - | - |
| 2041 | | | SO | | - | - | - | - |
| 2042 | | | | B16 | 224,013,752 | - | 224,013,752 | - |
| 2043 | | | | | | | | |
| 2044 | 186W | Weatherization | | | | | | |
| 2045 | | | S | | - | - | - | - |
| 2046 | | | CN | | - | - | - | - |
| 2047 | | | CNP | | - | - | - | - |
| 2048 | | | SG | | - | - | - | - |
| 2049 | | | SO | | - | - | - | - |
| 2050 | | | | B16 | - | - | - | - |
| 2051 | | | | | | | | |
| 2052 | **Total Weatherization** | | | **B16** | **224,530,257** | **-** | **224,530,257** | **-** |
| 2053 | | | | | | | | |
| 2054 | 151 | Fuel Stock | | | | | | |
| 2055 | | | DEU | | - | - | - | - |
| 2056 | | | SE | | 142,169,743 | 37,446,258 | 171,446,926 | 45,157,610 |
| 2057 | | | SE | | - | - | - | - |
| 2058 | | | SE | | - | - | - | - |
| 2059 | | | | B13 | 142,169,743 | 37,446,258 | 171,446,926 | 45,157,610 |
| 2060 | | | | | | | | |
| 2061 | 152 | Fuel Stock - Undistributed | | | | | | |
| 2062 | | | SE | | - | - | - | - |
| 2063 | | | | | - | - | - | - |
| 2064 | | | | | | | | |
| 2065 | 25316 | UAMPS Working Capital Deposit | | | | | | |
| 2066 | | | SE | | (1,762,000) | (464,095) | (886,692) | (233,547) |
| 2067 | | | | B13 | (1,762,000) | (464,095) | (886,692) | (233,547) |
| 2068 | | | | | | | | |
| 2069 | 25317 | DG&T Working Capital Deposit | | | | | | |
| 2070 | | | SE | | (2,802,703) | (738,207) | (5,238,916) | (1,379,884) |
| 2071 | | | | B13 | (2,802,703) | (738,207) | (5,238,916) | (1,379,884) |
| 2072 | | | | | | | | |
| 2073 | 25319 | Provo Working Capital Deposit | | | | | | |
| 2074 | | | SE | | - | - | - | - |
| 2075 | | | | | - | - | - | - |
| 2076 | | | | | | | | |
| 2077 | **Total Fuel Stock** | | | **B13** | **137,605,040** | **36,243,955** | **165,321,317** | **43,544,178** |
| 2078 | 154 | Materials and Supplies | | | | | | |
| 2079 | | | S | | 250,693,096 | 92,111,560 | 250,693,096 | 92,111,560 |
| 2080 | | | SG | | (126,807) | (34,091) | (126,807) | (34,091) |
| 2081 | | | SE | | - | - | - | - |
| 2082 | | | SO | | (824,409) | (226,098) | (824,409) | (226,098) |
| 2083 | | | SG | | 134,063,446 | 36,041,827 | 134,063,446 | 36,041,827 |
| 2084 | | | SG | | 33,938 | 9,124 | 33,938 | 9,124 |
| 2085 | | | SNPD | | (1,319,331) | (329,812) | (1,319,331) | (329,812) |
| 2086 | | | SG | | - | - | - | - |
| 2087 | | | SG | | - | - | - | - |
| 2088 | | | SG | | - | - | - | - |
| 2089 | | | SG | | - | - | - | - |
| 2090 | | | SG | | 8,640,607 | 2,322,954 | 8,640,607 | 2,322,954 |
| 2091 | | | SG | | - | - | - | - |
| 2092 | | | | B13 | 391,160,539 | 129,895,465 | 391,160,539 | 129,895,465 |
| 2093 | | | | | | | | |
| 2094 | 158 | WA GHG Allocation Inventory | | | | | | |
| 2095 | | | S | | 16,242,900 | - | 16,242,900 | - |
| 2096 | | | | | | | | |
| 2097 | | | | B13 | 16,242,900 | - | 16,242,900 | - |

| | 2020 PROTOCOL<br>Year End<br>FERC<br>ACCT | DESCRIP | FACTOR | Ref | JUNE 2023<br>UNADJUSTED RESULTS<br>TOTAL | <br><br>OREGON | DECEMBER 2025<br>NORMALIZED RESULTS<br>TOTAL | <br><br>OREGON |
|---|---|---|---|---|---|---|---|---|
| 2098 | | | | | | | | |
| 2099 | 25318 | Provo Working Capital Deposit | | | | | | |
| 2100 | | | SG | | (273,000) | (73,394) | (273,000) | (73,394) |
| 2101 | | | | | | | | |
| 2102 | | | | B13 | (273,000) | (73,394) | (273,000) | (73,394) |
| 2103 | | | | | | | | |
| 2104 | **Total Materials and Supplies** | | | **B13** | **407,130,439** | **129,822,071** | **407,130,439** | **129,822,071** |
| 2105 | | | | | | | | |
| 2106 | 165 | Prepayments | | | | | | |
| 2107 | | | S | | 51,220,696 | 4,549,813 | 51,220,696 | 4,549,813 |
| 2108 | | | GPS | | 197,660 | 54,209 | 197,660 | 54,209 |
| 2109 | | | SG | | 6,134,385 | 1,649,178 | 6,134,385 | 1,649,178 |
| 2110 | | | SE | | 587,701 | 154,795 | 587,701 | 154,795 |
| 2111 | | | SO | | 38,031,038 | 10,430,189 | 38,031,038 | 10,430,189 |
| 2112 | **Total Prepayments** | | | **B15** | **96,171,480** | **16,838,184** | **96,171,480** | **16,838,184** |
| 2113 | | | | | | | | |
| 2114 | 182M | Misc Regulatory Assets | | | | | | |
| 2115 | | | S | | 957,717,305 | 236,341 | 952,590,630 | 75,123 |
| 2116 | | | SG | | 11,149,670 | 2,997,495 | - | - |
| 2117 | | | SGCT | | - | - | - | - |
| 2118 | | | SG-P | | - | - | - | - |
| 2119 | | | SE | | 190,387,608 | 50,146,418 | 128,271,840 | 33,785,672 |
| 2120 | | | SG | | - | - | - | - |
| 2121 | | | SO | | 318,139,567 | 87,251,258 | 85,397,886 | 23,420,768 |
| 2122 | | | | B16 | 1,477,394,149 | 140,631,513 | 1,166,260,355 | 57,281,563 |
| 2123 | | | | | | | | |
| 2124 | 186M | Misc Deferred Debits | | | | | | |
| 2125 | | | S | | 3,427,151 | - | 3,427,151 | - |
| 2126 | | | SG | | - | - | - | - |
| 2127 | | | SG | | - | - | - | - |
| 2128 | | | SG | | 155,505,931 | 41,806,459 | 145,190,746 | 39,033,308 |
| 2129 | | | SO | | - | - | - | - |
| 2130 | | | SE | | 306,510 | 80,732 | 306,510 | 80,732 |
| 2131 | | | SG | | - | - | - | - |
| 2132 | | | EXCTAX | | - | - | - | - |
| 2133 | **Total Misc. Deferred Debits** | | | **B11** | **159,239,593** | **41,887,191** | **148,924,407** | **39,114,040** |
| 2134 | | | | | | | | |
| 2135 | Working Capital | | | | | | | |
| 2136 | CWC | Cash Working Capital | | | | | | |
| 2137 | | | S | | 86,606,808 | 35,213,620 | 84,900,755 | 36,361,381 |
| 2138 | | | SO | | - | - | - | - |
| 2139 | | | SE | | - | - | - | - |
| 2140 | | | | B14 | 86,606,808 | 35,213,620 | 84,900,755 | 36,361,381 |
| 2141 | | | | | | | | |
| 2142 | OWC | Other Work. Cap. | | | | | | |
| 2143 | 131 | Cash | SNP | | - | - | - | - |
| 2144 | 135 | Working Funds | SG | | - | - | - | - |
| 2145 | 141 | Notes Receivable | SO | | - | - | - | - |
| 2146 | 143 | Other A/R | SO | | 67,575,159 | 18,532,802 | 67,575,159 | 18,532,802 |
| 2147 | 232 | A/P | S | | (24,331) | - | (24,331) | - |
| 2148 | 232 | A/P | SO | | (6,461,727) | (1,772,159) | (6,461,727) | (1,772,159) |
| 2149 | 232 | A/P | SE | | (2,815,901) | (741,683) | (2,815,901) | (741,683) |
| 2150 | 232 | A/P | SG | | (4,621,875) | (1,242,552) | (4,621,875) | (1,242,552) |
| 2151 | 2533 | Other Msc. Df. Crd. | S | | - | - | - | - |
| 2152 | 2533 | Other Msc. Df. Crd. | SE | | (10,815,889) | (2,848,810) | (11,135,301) | (2,932,940) |
| 2153 | 230 | Asset Retir. Oblig. | SG | | - | - | - | - |
| 2154 | 230 | Asset Retir. Oblig. | S | | (2,022,628) | - | (2,022,628) | - |
| 2155 | 254 | Decom. Reg Liability | SG | | - | - | - | - |
| 2156 | 254 | Reclam. Reg Liability | SE | | - | - | - | - |
| 2157 | 2533 | Cholla Reclamation | SE | | - | - | - | - |
| 2158 | | | | B14 | 40,812,809 | 11,927,598 | 40,493,397 | 11,843,468 |
| 2159 | | | | | | | | |
| 2160 | **Total Working Capital** | | | **B14** | **127,419,617** | **47,141,218** | **125,394,152** | **48,204,849** |
| 2161 | Miscellaneous Rate Base | | | | | | | |
| 2162 | 18221 | Unrec Plant & Reg Study Costs | | | | | | |
| 2163 | | | S | | - | - | - | - |
| 2164 | | | | | | | | |
| 2165 | | | | | - | - | - | - |
| 2166 | | | | | | | | |
| 2167 | 18222 | Nuclear Plant - Trojan | | | | | | |
| 2168 | | | S | | - | - | - | - |
| 2169 | | | TROJP | | - | - | - | - |
| 2170 | | | TROJD | | - | - | - | - |
| 2171 | | | | B16 | - | - | - | - |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 2172 | | | | | | | | |
| 2173 | | | | | | | | |
| 2174 | | | | | | | | |
| 2175 | 1869 | Misc Deferred Debits-Trojan | | | | | | |
| 2176 | | | S | | - | - | (98,566) | (98,566) |
| 2177 | | | SG | | - | - | - | - |
| 2178 | | | | | - | - | (98,566) | (98,566) |
| 2179 | | | | | | | | |
| 2180 | **Total Miscellaneous Rate Base** | | | **B15** | **-** | **-** | **(98,566)** | **(98,566)** |
| 2181 | | | | | | | | |
| 2182 | **Total Rate Base Additions** | | | | **2,760,570,713** | **449,532,455** | **2,345,512,659** | **335,409,568** |
| 2183 | 235 | Customer Service Deposits | | | | | | |
| 2184 | | | S | | - | - | - | - |
| 2185 | | | CN | | - | - | - | - |
| 2186 | **Total Customer Service Deposits** | | | B15 | - | - | - | - |
| 2187 | | | | | | | | |
| 2188 | 2281 | Prop Ins | S | | (967,647) | 31,639,210 | (967,647) | 31,639,210 |
| 2189 | 2282 | Inj & Dam | SO | | (526,198,873) | (144,312,492) | - | - |
| 2190 | 2283 | Pen & Ben | SO | | (1,252,613) | (343,535) | (1,252,613) | (343,535) |
| 2191 | 2282 | Prov for Injuries & Da | S | | (4,316,923) | (4,316,923) | 5,479,612 | 5,479,612 |
| 2192 | 2281 | Prop Ins | SO | | (10,000,000) | (2,742,547) | - | - |
| 2193 | 25335 | Reg Liabilities | SE | | (115,119,099) | (30,321,356) | (115,119,099) | (30,321,356) |
| 2194 | | | | B15 | (657,855,155) | (150,397,643) | (111,859,747) | 6,453,930 |
| 2195 | | | | | | | | |
| 2196 | 22841 | Accum Misc. Operating Provisions | | | | | | |
| 2197 | | | S | | - | - | - | - |
| 2198 | | | SG | | (234,889) | (63,148) | (234,889) | (63,148) |
| 2199 | | | | B15 | (234,889) | (63,148) | (234,889) | (63,148) |
| 2200 | | | | | | | | |
| 2201 | 254105 | ARO | S | | - | - | - | - |
| 2202 | 230 | ARO | TROJD | | (6,946,250) | (1,860,674) | (6,946,250) | (1,860,674) |
| 2203 | 254 | Reg Liabilities | SO | | (33,831,393) | (9,278,417) | (33,831,393) | (9,278,417) |
| 2204 | 254 | | S | | (1,517,888,367) | (359,427,149) | (1,497,074,689) | (338,613,472) |
| 2205 | | | | B15 | (1,558,666,010) | (370,566,240) | (1,537,852,333) | (349,752,563) |
| 2206 | | | | | | | | |
| 2207 | 252 | Customer Advances for Construction | | | | | | |
| 2208 | | | S | | (31,225,486) | (30,377,839) | (39,124,188) | (5,177,396) |
| 2209 | | | SE | | - | - | - | - |
| 2210 | | | SG | | (162,194,505) | (43,604,625) | (154,295,803) | (41,481,126) |
| 2211 | | | SO | | - | - | - | - |
| 2212 | | | CN | | - | - | - | - |
| 2213 | **Total Customer Advances for Construction** | | | **B20** | **(193,419,991)** | **(73,982,464)** | **(193,419,991)** | **(46,658,522)** |
| 2214 | | | | | | | | |
| 2215 | 25398 | SO2 Emissions | | | | | | |
| 2216 | | | SE | | - | - | - | - |
| 2217 | | | | | - | - | - | - |
| 2218 | | | | | | | | |
| 2219 | 25399 | Other Deferred Credits | | | | | | |
| 2220 | | | S | | (75,556,188) | (331,064) | (75,556,188) | (331,064) |
| 2221 | | | SO | | (12,178,111) | (3,339,904) | (12,178,111) | (3,339,904) |
| 2222 | | | SG | | (304,720,623) | (81,921,571) | (304,720,623) | (81,921,571) |
| 2223 | | | SE | | (15,783,288) | (4,157,179) | (15,783,288) | (4,157,179) |
| 2224 | | | | B15 | (408,238,211) | (89,749,718) | (408,238,211) | (89,749,718) |
| 2225 | | | | | | | | |
| 2226 | 190 | Accumulated Deferred Income Taxes | | | | | | |
| 2227 | | | S | | 378,209,035 | 89,316,945 | 376,238,926 | 80,908,155 |
| 2228 | | | CN | | - | - | - | - |
| 2229 | | | SO | | 203,180,962 | 55,723,325 | 46,622,158 | 12,786,344 |
| 2230 | | | DGP | | - | - | - | - |
| 2231 | | | IBT | | - | - | - | - |
| 2232 | | | SG | | - | - | - | - |
| 2233 | | | SG | | - | - | - | - |
| 2234 | | | BADDEBT | | 6,204,844 | 2,416,080 | 6,374,315 | 2,482,069 |
| 2235 | | | TROJD | | 1,177,177 | 315,327 | 1,151,728 | 308,510 |
| 2236 | | | SG | | 1,904,417 | 511,987 | 1,608,485 | 432,428 |
| 2237 | | | SE | | 32,356,562 | 8,522,433 | 4,247,960 | 1,118,875 |
| 2238 | | | SNP | | - | - | - | - |
| 2239 | | | SNPD | | 549,138 | 137,276 | 2,308,230 | 577,021 |
| 2240 | | | SG | | - | - | - | - |
| 2241 | | | | B19 | 623,582,135 | 156,943,372 | 438,551,802 | 98,613,403 |
| 2242 | | | | | | | | |
| 2243 | 281 | Accumulated Deferred Income Taxes | | | | | | |
| 2244 | | | S | | - | - | - | - |
| 2245 | | | SG | | (128,320,334) | (34,497,840) | (0) | (0) |
| 2246 | | | SG | | - | - | - | - |
| 2247 | | | | B19 | (128,320,334) | (34,497,840) | (0) | (0) |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 2248 | | | | | | | | |
| 2249 | 282 | Accumulated Deferred Income Taxes | | | | | | |
| 2250 | | | S | | 54,870,428 | 13,614,613 | (481,865,123) | (67,698,629) |
| 2251 | | | DITBAL | | (3,020,857,941) | (753,720,323) | (383,920) | (95,790) |
| 2252 | | | SNP | | (249,251) | (65,144) | (249,251) | (65,144) |
| 2253 | | | SO | | 1,450 | 398 | (141,407,158) | (38,781,572) |
| 2254 | | | GPS | | - | - | - | - |
| 2255 | | | CIAC | | - | - | - | - |
| 2256 | | | SNPD | | - | - | - | - |
| 2257 | | | SCHMDEXP | | - | - | - | - |
| 2258 | | | TAXDEPR | | - | - | - | - |
| 2259 | | | SG | | - | - | - | - |
| 2260 | | | IBT | | - | - | - | - |
| 2261 | | | SG | | - | - | - | - |
| 2262 | | | CN | | - | - | (21,827) | (6,702) |
| 2263 | | | SE | | (1,612,025) | (424,593) | (1,242,990) | (327,393) |
| 2264 | | | SG | | - | - | (2,482,770,307) | (667,471,869) |
| 2265 | | | | B19 | (2,967,847,339) | (740,595,049) | (3,107,940,576) | (774,447,098) |
| 2266 | | | | | | | | |
| 2267 | 283 | Accumulated Deferred Income Taxes | | | | | | |
| 2268 | | | S | | (281,809,078) | (8,730,572) | (291,231,674) | (8,897,652) |
| 2269 | | | SG | | (3,309,478) | (889,725) | (1,536,694) | (413,127) |
| 2270 | | | SE | | (35,177,917) | (9,265,553) | (613,153) | (161,499) |
| 2271 | | | SO | | (125,140,421) | (34,320,343) | (30,805,535) | (8,448,561) |
| 2272 | | | GPS | | (9,185,124) | (2,519,063) | (9,178,803) | (2,517,329) |
| 2273 | | | SNP | | (538,350) | (140,703) | (530,040) | (138,531) |
| 2274 | | | TROJD | | - | - | - | - |
| 2275 | | | SG | | - | - | - | - |
| 2276 | | | SG | | - | - | - | - |
| 2277 | | | SG | | - | - | - | - |
| 2278 | | | | B19 | (455,160,369) | (55,865,960) | (333,895,898) | (20,576,699) |
| 2279 | | | | | | | | |
| 2280 | **Total Accum Deferred Income Tax** | | | **B19** | **(2,927,745,908)** | **(674,015,477)** | **(3,003,284,673)** | **(696,410,395)** |
| 2281 | 255 | Accumulated Investment Tax Credit | | | | | | |
| 2282 | | | S | | (2,091,094) | - | (1,922,284) | - |
| 2283 | | | ITC84 | | - | - | - | - |
| 2284 | | | ITC85 | | - | - | - | - |
| 2285 | | | ITC86 | | - | - | - | - |
| 2286 | | | ITC88 | | - | - | - | - |
| 2287 | | | ITC89 | | - | - | - | - |
| 2288 | | | ITC90 | | - | - | - | - |
| 2289 | | | SG | | (169,745) | (45,635) | (152,202) | (40,918) |
| 2290 | **Total Accumulated ITC** | | | **B19** | **(2,260,839)** | **(45,635)** | **(2,074,486)** | **(40,918)** |
| 2291 | | | | | | | | |
| 2292 | **Total Rate Base Deductions** | | | | **(5,748,421,002)** | **(1,358,820,325)** | **(5,256,964,329)** | **(1,176,221,333)** |
| 2293 | | | | | | | | |
| 2294 | | | | | | | | |
| 2295 | | | | | | | | |
| 2296 | 108SP | Steam Prod Plant Accumulated Depr | | | | | | |
| 2297 | | | S | | (65,845,207) | - | (65,845,207) | - |
| 2298 | | | SG | | (824,873,009) | (221,760,155) | (824,873,009) | (221,760,155) |
| 2299 | | | SG | | (769,219,505) | (206,798,180) | (769,219,505) | (206,798,180) |
| 2300 | | | SG | | (2,339,730,354) | (629,016,783) | (3,997,300,692) | (1,074,640,597) |
| 2301 | | | SG | | - | - | - | - |
| 2302 | | | SG | | - | - | - | - |
| 2303 | | | | B17 | (3,999,668,075) | (1,057,575,119) | (5,657,238,413) | (1,503,198,932) |
| 2304 | | | | | | | | |
| 2305 | 108NP | Nuclear Prod Plant Accumulated Depr | | | | | | |
| 2306 | | | SG | | - | - | - | - |
| 2307 | | | SG | | - | - | - | - |
| 2308 | | | SG | | - | - | - | - |
| 2309 | | | | B17 | - | - | - | - |
| 2310 | | | | | | | | |
| 2311 | | | | | | | | |
| 2312 | 108HP | Hydraulic Prod Plant Accum Depr | | | | | | |
| 2313 | | | S | | - | - | - | - |
| 2314 | | | SG | | (145,923,755) | (39,230,371) | (145,923,755) | (39,230,371) |
| 2315 | | | SG | | (32,553,755) | (8,751,803) | (32,553,755) | (8,751,803) |
| 2316 | | | SG | | (199,044,187) | (53,511,352) | (222,822,330) | (59,903,905) |
| 2317 | | | SG | | (76,852,964) | (20,661,272) | (87,837,794) | (23,614,451) |
| 2318 | | | SG | | - | - | (6,619,615) | (1,779,628) |
| 2319 | | | | B17 | (454,374,661) | (122,154,798) | (495,757,249) | (133,280,158) |
| 2320 | | | | | | | | |
| 2321 | 108OP | Other Production Plant - Accum Depr | | | | | | |
| 2322 | | | S | | (44,745) | (310) | (173,198,503) | (173,154,068) |
| 2323 | | | SG | | - | - | - | - |
| 2324 | | | SG | | 117,259,199 | 31,524,147 | (91,457,351) | (24,587,538) |
| 2325 | | | SG | | (568,854,645) | (152,931,776) | (641,654,082) | (172,503,291) |
| 2326 | | | SG | | (50,136,554) | (13,478,790) | (50,136,554) | (13,478,790) |
| 2327 | | | | B17 | (501,776,746) | (134,886,729) | (956,446,490) | (383,723,687) |
| 2328 | | | | | | | | |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 2329 | 108EP | Experimental Plant - Accum Depr | | | | | | |
| 2330 | | | SG | | - | - | - | - |
| 2331 | | | SG | | - | - | - | - |
| 2332 | | | | | - | - | - | - |
| 2333 | | | | | | | | |
| 2334 | **Total Production Plant Accum Depreciation** | | | **B17** | **(4,955,819,482)** | **(1,314,616,645)** | **(7,109,442,153)** | **(2,020,202,776)** |
| 2335 | | | | | | | | |
| 2336 | Summary of Prod Plant Depreciation by Factor | | | | | | | |
| 2337 | | S | | | (65,889,953) | (310) | (239,043,711) | (173,154,068) |
| 2338 | | DGP | | | - | - | - | - |
| 2339 | | DGU | | | - | - | - | - |
| 2340 | | SG | | | (4,889,929,529) | (1,314,616,335) | (6,870,398,442) | (1,847,048,708) |
| 2341 | | SSGCH | | | - | - | - | - |
| 2342 | | SSGCT | | | - | - | - | - |
| 2343 | Total of Prod Plant Depreciation by Factor | | | | (4,955,819,482) | (1,314,616,645) | (7,109,442,153) | (2,020,202,776) |
| 2344 | | | | | | | | |
| 2345 | | | | | | | | |
| 2346 | 108TP | Transmission Plant Accumulated Depr | | | | | | |
| 2347 | | | SG | | (349,536,968) | (93,970,067) | (349,536,968) | (93,970,067) |
| 2348 | | | SG | | (420,976,303) | (113,175,930) | (420,976,303) | (113,175,930) |
| 2349 | | | SG | | (1,424,968,812) | (383,090,854) | (1,654,652,610) | (444,839,407) |
| 2350 | **Total Trans Plant Accum Depreciation** | | | **B17** | **(2,195,482,082)** | **(590,236,851)** | **(2,425,165,880)** | **(651,985,404)** |
| 2351 | 108360 | Land and Land Rights | | | | | | |
| 2352 | | | S | | (10,428,264) | (2,501,052) | (12,267,420) | (2,858,488) |
| 2353 | | | | B17 | (10,428,264) | (2,501,052) | (12,267,420) | (2,858,488) |
| 2354 | | | | | | | | |
| 2355 | 108361 | Structures and Improvements | | | | | | |
| 2356 | | | S | | (36,908,591) | (9,863,390) | (40,436,632) | (10,548,995) |
| 2357 | | | | B17 | (36,908,591) | (9,863,390) | (40,436,632) | (10,548,995) |
| 2358 | | | | | | | | |
| 2359 | 108362 | Station Equipment | | | | | | |
| 2360 | | | S | | (379,219,430) | (106,831,385) | (408,819,501) | (112,577,498) |
| 2361 | | | | B17 | (379,219,430) | (106,831,385) | (408,819,501) | (112,577,498) |
| 2362 | | | | | | | | |
| 2363 | 108363 | Storage Battery Equipment | | | | | | |
| 2364 | | | S | | - | - | - | - |
| 2365 | | | | B17 | - | - | - | - |
| 2366 | | | | | | | | |
| 2367 | 108364 | Poles, Towers & Fixtures | | | | | | |
| 2368 | | | S | | (718,134,437) | (269,538,865) | (754,546,320) | (276,584,933) |
| 2369 | | | | B17 | (718,134,437) | (269,538,865) | (754,546,320) | (276,584,933) |
| 2370 | | | | | | | | |
| 2371 | 108365 | Overhead Conductors | | | | | | |
| 2372 | | | S | | (364,755,336) | (143,460,816) | (387,395,342) | (147,706,066) |
| 2373 | | | | B17 | (364,755,336) | (143,460,816) | (387,395,342) | (147,706,066) |
| 2374 | | | | | | | | |
| 2375 | 108366 | Underground Conduit | | | | | | |
| 2376 | | | S | | (191,409,398) | (51,732,079) | (203,001,054) | (53,984,823) |
| 2377 | | | | B17 | (191,409,398) | (51,732,079) | (203,001,054) | (53,984,823) |
| 2378 | | | | | | | | |
| 2379 | 108367 | Underground Conductors | | | | | | |
| 2380 | | | S | | (406,334,486) | (102,482,947) | (432,737,093) | (107,614,232) |
| 2381 | | | | B17 | (406,334,486) | (102,482,947) | (432,737,093) | (107,614,232) |
| 2382 | | | | | | | | |
| 2383 | 108368 | Line Transformers | | | | | | |
| 2384 | | | S | | (636,665,915) | (262,971,898) | (675,209,628) | (270,462,078) |
| 2385 | | | | B17 | (636,665,915) | (262,971,898) | (675,209,628) | (270,462,078) |
| 2386 | | | | | | | | |
| 2387 | 108369 | Services | | | | | | |
| 2388 | | | S | | (395,631,698) | (156,860,755) | (420,220,316) | (161,639,339) |
| 2389 | | | | B17 | (395,631,698) | (156,860,755) | (420,220,316) | (161,639,339) |
| 2390 | | | | | | | | |
| 2391 | 108370 | Meters | | | | | | |
| 2392 | | | S | | (112,190,330) | (32,684,776) | (119,165,119) | (34,040,310) |
| 2393 | | | | B17 | (112,190,330) | (32,684,776) | (119,165,119) | (34,040,310) |
| 2394 | | | | | | | | |
| 2395 | | | | | | | | |
| 2396 | | | | | | | | |
| 2397 | 108371 | Installations on Customers' Premises | | | | | | |
| 2398 | | | S | | (7,248,581) | (2,123,577) | (7,459,419) | (2,164,552) |
| 2399 | | | | B17 | (7,248,581) | (2,123,577) | (7,459,419) | (2,164,552) |
| 2400 | | | | | | | | |
| 2401 | 108372 | Leased Property | | | | | | |
| 2402 | | | S | | - | - | - | - |
| 2403 | | | | B17 | - | - | - | - |
| 2404 | | | | | | | | |
| 2405 | 108373 | Street Lights | | | | | | |
| 2406 | | | S | | (33,584,203) | (12,324,304) | (35,085,741) | (12,616,113) |
| 2407 | | | | B17 | (33,584,203) | (12,324,304) | (35,085,741) | (12,616,113) |

| | 2020 PROTOCOL<br>Year End<br>FERC<br>ACCT | DESCRIP | FACTOR | Ref | JUNE 2023<br>UNADJUSTED RESULTS<br>TOTAL | <br><br>OREGON | DECEMBER 2025<br>NORMALIZED RESULTS<br>TOTAL | <br><br>OREGON |
|---|---|---|---|---|---|---|---|---|
| 2408 | | | | | | | | |
| 2409 | 108D00 | Unclassified Dist Plant - Acct 300 | | | | | | |
| 2410 | | | S | | - | - | - | - |
| 2411 | | | | B17 | - | - | - | - |
| 2412 | | | | | | | | |
| 2413 | 108DS | Unclassified Dist Sub Plant - Acct 300 | | | | | | |
| 2414 | | | S | | - | - | - | - |
| 2415 | | | | B17 | - | - | - | - |
| 2416 | | | | | | | | |
| 2417 | 108DP | Unclassified Dist Sub Plant - Acct 300 | | | | | | |
| 2418 | | | S | | 2,140,729 | 685,999 | 2,140,729 | 685,999 |
| 2419 | | | | B17 | 2,140,729 | 685,999 | 2,140,729 | 685,999 |
| 2420 | | | | | | | | |
| 2421 | | | | | | | | |
| 2422 | **Total Distribution Plant Accum Depreciation** | | | **B17** | **(3,290,369,938)** | **(1,152,689,844)** | **(3,494,202,854)** | **(1,192,111,426)** |
| 2423 | | | | | | | | |
| 2424 | Summary of Distribution Plant Depr by Factor | | | | | | | |
| 2425 | | S | | | (3,290,369,938) | (1,152,689,844) | (3,494,202,854) | (1,192,111,426) |
| 2426 | | | | | | | | |
| 2427 | Total Distribution Depreciation by Factor | | | | (3,290,369,938) | (1,152,689,844) | (3,494,202,854) | (1,192,111,426) |
| 2428 | 108GP | General Plant Accumulated Depr | | | | | | |
| 2429 | | | S | | (303,587,815) | (91,214,708) | (330,848,307) | (96,741,359) |
| 2430 | | | SG | | (473,066) | (127,180) | (473,066) | (127,180) |
| 2431 | | | SG | | (2,092,186) | (562,467) | (2,092,186) | (562,467) |
| 2432 | | | SG | | (142,888,014) | (38,414,238) | (155,924,142) | (41,918,891) |
| 2433 | | | CN | | (6,304,713) | (1,935,895) | (5,485,751) | (1,684,429) |
| 2434 | | | SO | | (121,429,156) | (33,302,512) | (135,829,842) | (37,251,967) |
| 2435 | | | SE | | (1,798,513) | (473,712) | (1,912,546) | (503,748) |
| 2436 | | | SG | | (149,363) | (40,155) | (149,363) | (40,155) |
| 2437 | | | SG | | - | - | - | - |
| 2438 | | | | B17 | (578,722,825) | (166,070,867) | (632,715,203) | (178,830,195) |
| 2439 | | | | | | | | |
| 2440 | | | | | | | | |
| 2441 | 108MP | Mining Plant Accumulated Depr. | | | | | | |
| 2442 | | | S | | - | - | - | - |
| 2443 | | | SE | | - | - | - | - |
| 2444 | | | | B17 | - | - | - | - |
| 2445 | 108MP | Less Centralia Situs Depreciation | | | | | | |
| 2446 | | | S | | - | - | - | - |
| 2447 | | | | B17 | - | - | - | - |
| 2448 | | | | | | | | |
| 2449 | 1081390 | Accum Depr - Capital Lease | | | | | | |
| 2450 | | | SO | B17 | - | - | - | - |
| 2451 | | | | | - | - | - | - |
| 2452 | | | | | | | | |
| 2453 | | Remove Capital Leases | | | - | - | - | - |
| 2454 | | | | B17 | - | - | - | - |
| 2455 | | | | | | | | |
| 2456 | 1081399 | Accum Depr - Capital Lease | | | | | | |
| 2457 | | | S | | - | - | - | - |
| 2458 | | | SE | B17 | - | - | - | - |
| 2459 | | | | | - | - | - | - |
| 2460 | | | | | | | | |
| 2461 | | Remove Capital Leases | | | - | - | - | - |
| 2462 | | | | B17 | - | - | - | - |
| 2463 | | | | | | | | |
| 2464 | | | | | | | | |
| 2465 | **Total General Plant Accum Depreciation** | | | **B17** | **(578,722,825)** | **(166,070,867)** | **(632,715,203)** | **(178,830,195)** |
| 2466 | | | | | | | | |
| 2467 | | | | | | | | |
| 2468 | | | | | | | | |
| 2469 | Summary of General Depreciation by Factor | | | | | | | |
| 2470 | | S | | | (303,587,815) | (91,214,708) | (330,848,307) | (96,741,359) |
| 2471 | | DGP | | | - | - | - | - |
| 2472 | | DGU | | | - | - | - | - |
| 2473 | | SE | | | (1,798,513) | (473,712) | (1,912,546) | (503,748) |
| 2474 | | SO | | | (121,429,156) | (33,302,512) | (135,829,842) | (37,251,967) |
| 2475 | | CN | | | (6,304,713) | (1,935,895) | (5,485,751) | (1,684,429) |
| 2476 | | SG | | | (145,602,629) | (39,144,039) | (158,638,757) | (42,648,693) |
| 2477 | | DEU | | | - | - | - | - |
| 2478 | | SSGCT | | | - | - | - | - |
| 2479 | | SSGCH | | | - | - | - | - |
| 2480 | | Remove Capital Leases | | | - | - | - | - |
| 2481 | Total General Depreciation by Factor | | | | (578,722,825) | (166,070,867) | (632,715,203) | (178,830,195) |
| 2482 | | | | | | | | |
| 2483 | | | | | | | | |
| 2484 | **Total Accum Depreciation - Plant In Service** | | | **B17** | **(11,020,394,328)** | **(3,223,614,207)** | **(13,661,526,090)** | **(4,043,129,802)** |

| | 2020 PROTOCOL Year End FERC ACCT | DESCRIP | FACTOR | Ref | JUNE 2023 UNADJUSTED RESULTS TOTAL | JUNE 2023 UNADJUSTED RESULTS OREGON | DECEMBER 2025 NORMALIZED RESULTS TOTAL | DECEMBER 2025 NORMALIZED RESULTS OREGON |
|---|---|---|---|---|---|---|---|---|
| 2485 | 111OP | Accum Prov for Amort-Other | | | | | | |
| 2486 | | | S | | (92,148) | (92,148) | (198,109) | (198,109) |
| 2487 | | | SG | | - | - | - | - |
| 2488 | | | | B18 | (92,148) | (92,148) | (198,109) | (198,109) |
| 2489 | | | | | | | | |
| 2490 | | | | | | | | |
| 2491 | 111GP | Accum Prov for Amort-General | | | | | | |
| 2492 | | | S | | (12,628,554) | (5,064,283) | (13,259,862) | (5,273,651) |
| 2493 | | | CN | | - | - | - | - |
| 2494 | | | SG | | - | - | - | - |
| 2495 | | | SO | | (1,442,803) | (395,695) | (1,504,848) | (412,712) |
| 2496 | | | SE | | - | - | - | - |
| 2497 | | | | B18 | (14,071,356) | (5,459,979) | (14,764,710) | (5,686,363) |
| 2498 | | | | | | | | |
| 2499 | | | | | | | | |
| 2500 | 111HP | Accum Prov for Amort-Hydro | | | | | | |
| 2501 | | | SG | | - | - | - | - |
| 2502 | | | SG | | - | - | - | - |
| 2503 | | | SG | | (3,764,748) | (1,012,121) | (4,235,565) | (1,138,696) |
| 2504 | | | SG | | - | - | - | - |
| 2505 | | | | B18 | (3,764,748) | (1,012,121) | (4,235,565) | (1,138,696) |
| 2506 | | | | | | | | |
| 2507 | | | | | | | | |
| 2508 | 111IP | Accum Prov for Amort-Intangible Plant | | | | | | |
| 2509 | | | S | | (1,666,939) | (149,822) | (1,871,328) | (159,409) |
| 2510 | | | SG | | - | - | - | - |
| 2511 | | | SG | | (421,999) | (113,451) | (421,999) | (113,451) |
| 2512 | | | SE | | (5,540) | (1,459) | (2,923) | (770) |
| 2513 | | | SG | | (108,800,207) | (29,250,019) | (116,718,993) | (31,378,917) |
| 2514 | | | SG | | (45,827,311) | (12,320,286) | (49,765,034) | (13,378,910) |
| 2515 | | | SG | | (6,403,898) | (1,721,634) | (6,610,880) | (1,777,279) |
| 2516 | | | CN | | (185,912,323) | (57,085,366) | (206,894,836) | (63,528,158) |
| 2517 | | | SG | | - | - | - | - |
| 2518 | | | SG | | - | - | - | - |
| 2519 | | | SO | | (364,651,322) | (100,007,324) | (409,857,468) | (112,405,320) |
| 2520 | | | | B18 | (713,689,539) | (200,649,360) | (792,143,460) | (222,742,214) |
| 2521 | 111IP | Less Non-Regulated Plant | | | | | | |
| 2522 | | | OTH | | - | - | - | - |
| 2523 | | | | | (713,689,539) | (200,649,360) | (792,143,460) | (222,742,214) |
| 2524 | | | | | | | | |
| 2525 | 111390 | Accum Amtr - Capital Lease | | | | | | |
| 2526 | | | S | | - | - | - | - |
| 2527 | | | SG | | - | - | - | - |
| 2528 | | | SO | | - | - | - | - |
| 2529 | | | | B9 | - | - | - | - |
| 2530 | | | | | | | | |
| 2531 | | Remove Capital Lease Amtr | | | - | - | - | - |
| 2532 | | | | | | | | |
| 2533 | **Total Accum Provision for Amortization** | | | **B18** | **(731,617,791)** | **(207,213,607)** | **(811,341,845)** | **(229,765,382)** |
| 2534 | | | | | | | | |
| 2535 | | | | | | | | |
| 2536 | | | | | | | | |
| 2537 | | | | | | | | |
| 2538 | Summary of Amortization by Factor | | | | | | | |
| 2539 | | S | | | (14,387,640) | (5,306,253) | (15,329,299) | (5,631,169) |
| 2540 | | DGP | | | - | - | - | - |
| 2541 | | DGU | | | - | - | - | - |
| 2542 | | SE | | | (5,540) | (1,459) | (2,923) | (770) |
| 2543 | | SO | | | (366,094,125) | (100,403,019) | (411,362,316) | (112,818,031) |
| 2544 | | CN | | | (185,912,323) | (57,085,366) | (206,894,836) | (63,528,158) |
| 2545 | | SSGCT | | | - | - | - | - |
| 2546 | | SSGCH | | | - | - | - | - |
| 2547 | | SG | | | (165,218,164) | (44,417,511) | (177,752,471) | (47,787,254) |
| 2548 | | Less Capital Lease | | | - | - | - | - |
| 2549 | Total Provision For Amortization by Factor | | | | (731,617,791) | (207,213,607) | (811,341,845) | (229,765,382) |

# Tab 1 - Retc l sc

**PacifiCorp** 
**Oregon General Rate Case – December 2025**
**Revenue Adjustment Index**

The Company used actual revenue for the 12 months ended June 30, 2023 as the starting point for the calculation of pro forma revenue. Actual revenue was adjusted using the normalizing and pro forma adjustments below to calculate the revenue for the December 2025 test period.

3.1 Pro Forma Revenues
3.2 REC Revenue
3.3 Wheeling Revenue
3.4_R Fly Ash Revenue

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Tab 3 Adjustment Summary**

| | | Total Adjustments | 3.1 Pro Forma Revenues | 3.2 REC Revenues_CONF | 3.3 Wheeling Revenue | 3.4_R Fly Ash Revenue |
|---|---|---|---|---|---|---|
| 1 | Operating Revenues: | | | | | |
| 2 | General Business Revenues | 280,144,493 | 280,144,493 | - | - | - |
| 3 | Interdepartmental | - | - | - | - | - |
| 4 | Special Sales | - | - | - | - | - |
| 5 | Other Operating Revenues | 1,450,937 | - | (1,404,981) | 4,508,033 | (1,652,114) |
| 6 | Total Operating Revenues | 281,595,430 | 280,144,493 | (1,404,981) | 4,508,033 | (1,652,114) |
| 7 | | | | | | |
| 8 | Operating Expenses: | | | | | |
| 9 | Steam Production | - | - | - | - | - |
| 10 | Nuclear Production | - | - | - | - | - |
| 11 | Hydro Production | - | - | - | - | - |
| 12 | Other Power Supply | - | - | - | - | - |
| 13 | Transmission | - | - | - | - | - |
| 14 | Distribution | - | - | - | - | - |
| 15 | Customer Accounting | - | - | - | - | - |
| 16 | Customer Service & Info | - | - | - | - | - |
| 17 | Sales | - | - | - | - | - |
| 18 | Administrative & General | - | - | - | - | - |
| 19 | | | | | | |
| 20 | Total O&M Expenses | - | - | - | - | - |
| 21 | | | | | | |
| 22 | Depreciation | - | - | - | - | - |
| 23 | Amortization | - | - | - | - | - |
| 24 | Taxes Other Than Income | - | - | - | - | - |
| 25 | Income Taxes - Federal | 56,439,197 | 56,148,390 | (281,596) | 903,529 | (331,128) |
| 26 | Income Taxes - State | 12,781,916 | 12,716,056 | (63,774) | 204,624 | (74,991) |
| 27 | Income Taxes - Def Net | - | - | - | - | - |
| 28 | Investment Tax Credit Adj. | - | - | - | - | - |
| 29 | Misc Revenue & Expense | - | - | - | - | - |
| 30 | | | | | | |
| 31 | Total Operating Expenses: | 69,221,112 | 68,864,447 | (345,369) | 1,108,154 | (406,119) |
| 32 | | | | | | |
| 33 | Operating Rev For Return: | 212,374,318 | 211,280,047 | (1,059,612) | 3,399,879 | (1,245,995) |
| 34 | | | | | | |
| 35 | Rate Base: | | | | | |
| 36 | Electric Plant In Service | - | - | - | - | - |
| 37 | Plant Held for Future Use | - | - | - | - | - |
| 38 | Misc Deferred Debits | - | - | - | - | - |
| 39 | Elec Plant Acq Adj | - | - | - | - | - |
| 40 | Nuclear Fuel | - | - | - | - | - |
| 41 | Prepayments | - | - | - | - | - |
| 42 | Fuel Stock | - | - | - | - | - |
| 43 | Material & Supplies | - | - | - | - | - |
| 44 | Working Capital | 2,100,248 | 2,089,426 | (10,479) | 33,623 | (12,322) |
| 45 | Weatherization Loans | - | - | - | - | - |
| 46 | Misc Rate Base | - | - | - | - | - |
| 47 | | | | | | |
| 48 | Total Electric Plant: | 2,100,248 | 2,089,426 | (10,479) | 33,623 | (12,322) |
| 49 | | | | | | |
| 50 | Rate Base Deductions: | | | | | |
| 51 | Accum Prov For Deprec | - | - | - | - | - |
| 52 | Accum Prov For Amort | - | - | - | - | - |
| 53 | Accum Def Income Tax | - | - | - | - | - |
| 54 | Unamortized ITC | - | - | - | - | - |
| 55 | Customer Adv For Const | - | - | - | - | - |
| 56 | Customer Service Deposits | - | - | - | - | - |
| 57 | Misc Rate Base Deductions | - | - | - | - | - |
| 58 | | | | | | |
| 59 | Total Rate Base Deductions | - | - | - | - | - |
| 60 | | | | | | |
| 61 | Total Rate Base: | 2,100,248 | 2,089,426 | (10,479) | 33,623 | (12,322) |
| 62 | | | | | | |
| 63 | Return on Rate Base | 4.417% | 4.394% | -0.022% | 0.071% | -0.026% |
| 64 | | | | | | |
| 65 | Return on Equity | 8.833% | 8.788% | -0.044% | 0.141% | -0.052% |
| 66 | | | | | | |
| 67 | TAX CALCULATION: | | | | | |
| 68 | Operating Revenue | 281,595,430 | 280,144,493 | (1,404,981) | 4,508,033 | (1,652,114) |
| 69 | Other Deductions | | - | - | - | - |
| 70 | Interest (AFUDC) | - | - | - | - | - |
| 71 | Interest | 55,435 | 55,150 | (277) | 887 | (325) |
| 72 | Schedule "M" Additions | - | - | - | - | - |
| 73 | Schedule "M" Deductions | - | - | - | - | - |
| 74 | Income Before Tax | 281,539,995 | 280,089,344 | (1,404,705) | 4,507,145 | (1,651,789) |
| 75 | | | | | | |
| 76 | State Income Taxes | 12,781,916 | 12,716,056 | (63,774) | 204,624 | (74,991) |
| 77 | Taxable Income | 268,758,079 | 267,373,287 | (1,340,931) | 4,302,521 | (1,576,798) |
| 78 | | | | | | |
| 79 | Federal Income Taxes + Other | 56,439,197 | 56,148,390 | (281,596) | 903,529 | (331,128) |
| | APPROXIMATE PRICE CHANGE | (291,517,421) | (290,017,170) | 1,452,733 | (4,661,248) | 1,708,265 |

**PacifiCorp** PAGE 3.4_R
**Oregon General Rate Case - December 2025**
**Fly Ash Revenue**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Revenues:** | | | | | | | |
| *Fly Ash Revenue* | *456* | *3* | *(6,145,308)* | *SG* | *26.884%* | *(1,652,114)* | *Below* |

**Adjustment Detail:**

| | |
|---|---|
| 12 Months Ended June 2023 | 14,065,194 |
| 12 Months Ending December 2025 | 7,919,886 |
| Adjustment | (6,145,308) |

**Description of Adjustment:**

This adjustment walks forward the level of fly ash sales revenue from the June 2023 Base Period to the December 2025 Test Period.

*This adjustment has been updated to reflect projected fly ash revenues consisting with the forecasted generation modelled in the Company's TAM settlement in Docket No. UE 435.*

# Tab 4 - Operation & Maintenance Expense

**Oregon General Rate Case – December 2025**
**Operation & Maintenance Expense Adjustment Index**

The Company's June 2023 actual O&M expenses are the basis for the test period O&M expenses. These actual expenses are adjusted for various normalizing items including labor costs, non-labor operation and maintenance, and inflation to reflect the appropriate level of on-going costs that the Company expects to incur during the December 2025 test period. The following adjustments are included:

4.1 Miscellaneous General Expense & Revenue
4.2_R Confidential Wages & Employee Benefits
4.3 Pension Related Non-Service Expense
4.4 Remove Non-Recurring Entries
4.5 Insurance Expense
4.6 Generation Overhaul Expense
4.7_R Revenue Sensitive Items & Uncollectible Accounts
4.8 Memberships & Subscriptions
4.9_R Meals and Entertainment Adjustment
4.10_R O&M Escalation
4.11 Wildfire & Vegetation Management O&M
4.12_R Customer Payment Fees
4.13 Incremental O&M

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Tab 4 Adjustment Summary**

| | | 4.1 | 4.2_R | 4.3 | 4.4 | 4.5 | 4.6 |
|---|---|---|---|---|---|---|---|
| | Total Adjustments | Miscellaneous General Expense & Revenue | Wage & Employee Benefits | Pension Related Non-Service Expense | Remove Non-Recurring Entries | Insurance Expense | Generation Overhaul Expense |
| 1 Operating Revenues: | | | | | | | |
| 2 General Business Revenues | 1,769,316 | 1,769,316 | - | - | - | - | - |
| 3 Interdepartmental | - | - | - | - | - | - | - |
| 4 Special Sales | - | - | - | - | - | - | - |
| 5 Other Operating Revenues | - | - | - | - | - | - | - |
| 6 Total Operating Revenues | 1,769,316 | 1,769,316 | - | - | - | - | - |
| 7 | | | | | | | |
| 8 Operating Expenses: | | | | | | | |
| 9 Steam Production | 283,685 | (2,240) | 1,607,524 | - | - | - | 535,268 |
| 10 Nuclear Production | - | - | - | - | - | - | - |
| 11 Hydro Production | 2,689,386 | - | 377,355 | - | 1,985,433 | - | - |
| 12 Other Power Supply | 2,644,070 | 256,891 | 639,679 | - | - | - | 761,814 |
| 13 Transmission | (1,954,519) | - | 612,965 | - | - | - | - |
| 14 Distribution | 9,124,295 | - | 3,128,296 | - | - | - | - |
| 15 Customer Accounting | 4,172,005 | (9,820) | 557,674 | - | - | - | - |
| 16 Customer Service & Info | 382,513 | 209,228 | 198,287 | - | - | - | - |
| 17 Sales | - | - | - | - | - | - | - |
| 18 Administrative & General | (110,810,560) | 434,876 | 413,258 | (8,432,127) | - | (105,258,061) | - |
| 19 | | | | | | | |
| 20 Total O&M Expenses | (93,469,126) | 888,935 | 7,535,038 | (8,432,127) | 1,985,433 | (105,258,061) | 1,297,082 |
| 21 | | | | | | | |
| 22 Depreciation | - | - | - | - | - | - | - |
| 23 Amortization | - | - | - | - | - | - | - |
| 24 Taxes Other Than Income | 6,690,549 | - | - | - | - | - | - |
| 25 Income Taxes - Federal | 18,651,924 | 172,302 | (1,511,431) | 1,691,376 | (398,252) | 22,008,059 | (260,178) |
| 26 Income Taxes - State | 4,224,145 | 39,022 | (342,297) | 383,050 | (90,193) | 4,984,216 | (58,923) |
| 27 Income Taxes - Def Net | (1,865,118) | - | - | - | - | (1,865,118) | - |
| 28 Investment Tax Credit Adj. | - | - | - | - | - | - | - |
| 29 Misc Revenue & Expense | 19,995 | 19,995 | - | - | - | - | - |
| 30 | | | | | | | |
| 31 Total Operating Expenses: | (65,747,631) | 1,120,253 | 5,681,310 | (6,357,702) | 1,496,987 | (80,130,904) | 977,981 |
| 32 | | | | | | | |
| 33 Operating Rev For Return: | 67,516,947 | 649,063 | (5,681,310) | 6,357,702 | (1,496,987) | 80,130,904 | (977,981) |
| 34 | | | | | | | |
| 35 Rate Base: | | | | | | | |
| 36 Electric Plant In Service | - | - | - | - | - | - | - |
| 37 Plant Held for Future Use | - | - | - | - | - | - | - |
| 38 Misc Deferred Debits | - | - | - | - | - | - | - |
| 39 Elec Plant Acq Adj | - | - | - | - | - | - | - |
| 40 Nuclear Fuel | - | - | - | - | - | - | - |
| 41 Prepayments | - | - | - | - | - | - | - |
| 42 Fuel Stock | - | - | - | - | - | - | - |
| 43 Material & Supplies | - | - | - | - | - | - | - |
| 44 Working Capital | (1,938,875) | 33,383 | 172,377 | (192,900) | 45,420 | (2,374,674) | 29,673 |
| 45 Weatherization Loans | - | - | - | - | - | - | - |
| 46 Misc Rate Base | - | - | - | - | - | - | - |
| 47 | | | | | | | |
| 48 Total Electric Plant: | (1,938,875) | 33,383 | 172,377 | (192,900) | 45,420 | (2,374,674) | 29,673 |
| 49 | | | | | | | |
| 50 Rate Base Deductions: | | | | | | | |
| 51 Accum Prov For Deprec | - | - | - | - | - | - | - |
| 52 Accum Prov For Amort | - | - | - | - | - | - | - |
| 53 Accum Def Income Tax | (38,564,469) | - | - | - | - | (38,564,469) | - |
| 54 Unamortized ITC | - | - | - | - | - | - | - |
| 55 Customer Adv For Const | - | - | - | - | - | - | - |
| 56 Customer Service Deposits | - | - | - | - | - | - | - |
| 57 Misc Rate Base Deductions | 156,851,573 | - | - | - | - | 156,851,573 | - |
| 58 | | | | | | | |
| 59 Total Rate Base Deductions | 118,287,105 | - | - | - | - | 118,287,105 | - |
| 60 | | | | | | | |
| 61 Total Rate Base: | 116,348,229 | 33,383 | 172,377 | (192,900) | 45,420 | 115,912,431 | 29,673 |
| 62 | | | | | | | |
| 63 Return on Rate Base | 1.209% | 0.013% | -0.118% | 0.133% | -0.031% | 1.466% | -0.020% |
| 64 | | | | | | | |
| 65 Return on Equity | 2.418% | 0.027% | -0.237% | 0.265% | -0.062% | 2.932% | -0.040% |
| 66 | | | | | | | |
| 67 TAX CALCULATION: | | | | | | | |
| 68 Operating Revenue | 88,527,898 | 860,387 | (7,535,038) | 8,432,127 | (1,985,433) | 105,258,061 | (1,297,082) |
| 69 Other Deductions | - | - | - | - | - | - | - |
| 70 Interest (AFUDC) | - | - | - | - | - | - | - |
| 71 Interest | 3,070,979 | 881 | 4,550 | (5,092) | 1,199 | 3,059,476 | 783 |
| 72 Schedule "M" Additions | 7,585,912 | - | - | - | - | 7,585,912 | - |
| 73 Schedule "M" Deductions | - | - | - | - | - | - | - |
| 74 Income Before Tax | 93,042,831 | 859,505 | (7,539,588) | 8,437,219 | (1,986,631) | 109,784,496 | (1,297,865) |
| 75 | | | | | | | |
| 76 State Income Taxes | 4,224,145 | 39,022 | (342,297) | 383,050 | (90,193) | 4,984,216 | (58,923) |
| 77 Taxable Income | 88,818,686 | 820,484 | (7,197,291) | 8,054,169 | (1,896,438) | 104,800,280 | (1,238,942) |
| 78 | | | | | | | |
| 79 Federal Income Taxes + Other | 18,651,924 | 172,302 | (1,511,431) | 1,691,376 | (398,252) | 22,008,059 | (260,178) |
| APPROXIMATE PRICE CHANGE | (80,765,766) | (887,326) | 7,812,466 | (8,742,585) | 2,058,533 | (98,068,318) | 1,344,839 |

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Tab 4 Adjustment Summary**

| | | 4.7_R Revenue Sensitive Items & Uncollectible Accounts | 4.8 Memberships and Subscriptions | 4.9_R Meals and Entertainment Adjustment | 4.10_R O&M Escalation | 4.11 Wildfire and Vegetation Management O&M | 4.12_R Customer Payment Fees | 4.13 Incremental O&M |
|---|---|---|---|---|---|---|---|---|
| 1 | Operating Revenues: | | | | | | | |
| 2 | General Business Revenues | - | - | - | - | - | - | - |
| 3 | Interdepartmental | - | - | - | - | - | - | - |
| 4 | Special Sales | - | - | - | - | - | - | - |
| 5 | Other Operating Revenues | - | - | - | - | - | - | - |
| 6 | Total Operating Revenues | - | - | - | - | - | - | - |
| 7 | | | | | | | | |
| 8 | Operating Expenses: | | | | | | | |
| 9 | Steam Production | - | - | (22,016) | 1,091,760 | - | - | (2,926,609) |
| 10 | Nuclear Production | - | - | - | - | - | - | - |
| 11 | Hydro Production | - | - | (8,218) | 75,919 | - | - | 258,897 |
| 12 | Other Power Supply | - | - | (21,394) | 1,007,079 | - | - | - |
| 13 | Transmission | - | - | (5,788) | (102,990) | (2,458,706) | - | - |
| 14 | Distribution | - | - | (73,075) | 633,777 | 5,435,297 | - | - |
| 15 | Customer Accounting | 1,717,034 | - | (4,443) | 340,955 | - | 1,570,606 | - |
| 16 | Customer Service & Info | - | - | (12,992) | (12,010) | - | - | - |
| 17 | Sales | - | - | - | - | - | - | - |
| 18 | Administrative & General | 1,259,216 | (172,095) | (79,121) | 1,023,495 | - | - | - |
| 19 | | | | | | | | |
| 20 | Total O&M Expenses | 2,976,249 | (172,095) | (227,049) | 4,057,985 | 2,976,591 | 1,570,606 | (2,667,712) |
| 21 | | | | | | | | |
| 22 | Depreciation | - | - | - | - | - | - | - |
| 23 | Amortization | - | - | - | - | - | - | - |
| 24 | Taxes Other Than Income | 6,690,549 | - | - | - | - | - | - |
| 25 | Income Taxes - Federal | (1,939,035) | 34,520 | 45,543 | (813,979) | (597,066) | (315,043) | 535,109 |
| 26 | Income Taxes - State | (439,138) | 7,818 | 10,314 | (184,344) | (135,219) | (71,349) | 121,187 |
| 27 | Income Taxes - Def Net | - | - | - | - | - | - | - |
| 28 | Investment Tax Credit Adj. | - | - | - | - | - | - | - |
| 29 | Misc Revenue & Expense | - | - | - | - | - | - | - |
| 30 | | | | | | | | |
| 31 | Total Operating Expenses: | 7,288,626 | (129,757) | (171,192) | 3,059,662 | 2,244,307 | 1,184,214 | (2,011,417) |
| 32 | | | | | | | | |
| 33 | Operating Rev For Return: | (7,288,626) | 129,757 | 171,192 | (3,059,662) | (2,244,307) | (1,184,214) | 2,011,417 |
| 34 | | | | | | | | |
| 35 | Rate Base: | | | | | | | |
| 36 | Electric Plant In Service | - | - | - | - | - | - | - |
| 37 | Plant Held for Future Use | - | - | - | - | - | - | - |
| 38 | Misc Deferred Debits | - | - | - | - | - | - | - |
| 39 | Elec Plant Acq Adj | - | - | - | - | - | - | - |
| 40 | Nuclear Fuel | - | - | - | - | - | - | - |
| 41 | Prepayments | - | - | - | - | - | - | - |
| 42 | Fuel Stock | - | - | - | - | - | - | - |
| 43 | Material & Supplies | - | - | - | - | - | - | - |
| 44 | Working Capital | 221,145 | (3,937) | (5,194) | 92,834 | 68,095 | 35,930 | (61,029) |
| 45 | Weatherization Loans | - | - | - | - | - | - | - |
| 46 | Misc Rate Base | - | - | - | - | - | - | - |
| 47 | | | | | | | | |
| 48 | Total Electric Plant: | 221,145 | (3,937) | (5,194) | 92,834 | 68,095 | 35,930 | (61,029) |
| 49 | | | | | | | | |
| 50 | Rate Base Deductions: | | | | | | | |
| 51 | Accum Prov For Deprec | - | - | - | - | - | - | - |
| 52 | Accum Prov For Amort | - | - | - | - | - | - | - |
| 53 | Accum Def Income Tax | - | - | - | - | - | - | - |
| 54 | Unamortized ITC | - | - | - | - | - | - | - |
| 55 | Customer Adv For Const | - | - | - | - | - | - | - |
| 56 | Customer Service Deposits | - | - | - | - | - | - | - |
| 57 | Misc Rate Base Deductions | - | - | - | - | - | - | - |
| 58 | | | | | | | | |
| 59 | Total Rate Base Deductions | - | - | - | - | - | - | - |
| 60 | | | | | | | | |
| 61 | Total Rate Base: | 221,145 | (3,937) | (5,194) | 92,834 | 68,095 | 35,930 | (61,029) |
| 62 | | | | | | | | |
| 63 | Return on Rate Base | -0.148% | 0.003% | 0.003% | -0.062% | -0.046% | -0.024% | 0.041% |
| 64 | | | | | | | | |
| 65 | Return on Equity | -0.297% | 0.005% | 0.007% | -0.125% | -0.091% | -0.048% | 0.082% |
| 66 | | | | | | | | |
| 67 | TAX CALCULATION: | | | | | | | |
| 68 | Operating Revenue | (9,666,799) | 172,095 | 227,049 | (4,057,985) | (2,976,591) | (1,570,606) | 2,667,712 |
| 69 | Other Deductions | - | - | - | - | - | - | - |
| 70 | Interest (AFUDC) | - | - | - | - | - | - | - |
| 71 | Interest | 5,837 | (104) | (137) | 2,450 | 1,797 | 948 | (1,611) |
| 72 | Schedule "M" Additions | - | - | - | - | - | - | - |
| 73 | Schedule "M" Deductions | - | - | - | - | - | - | - |
| 74 | Income Before Tax | (9,672,636) | 172,199 | 227,186 | (4,060,436) | (2,978,388) | (1,571,554) | 2,669,323 |
| 75 | | | | | | | | |
| 76 | State Income Taxes | (439,138) | 7,818 | 10,314 | (184,344) | (135,219) | (71,349) | 121,187 |
| 77 | Taxable Income | (9,233,498) | 164,381 | 216,872 | (3,876,092) | (2,843,170) | (1,500,206) | 2,548,136 |
| 78 | | | | | | | | |
| 79 | Federal Income Taxes + Other | (1,939,035) | 34,520 | 45,543 | (813,979) | (597,066) | (315,043) | 535,109 |
| | APPROXIMATE PRICE CHANGE | 9,973,738 | (178,620) | (235,657) | 4,206,158 | 3,089,863 | 1,630,374 | (2,769,230) |

**PacifiCorp** PAGE 4.2_R
**Oregon General Rate Case - December 2025**
**Confidential Wages & Employee Benefits**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Expense:** | | | | | | | |
| *Steam Operations* | *500* | *3* | *3,400,098* | *SG* | *26.884%* | *914,088* | |
| *Fuel Related-Non NPC* | *501* | *3* | *6,157* | *SE* | *26.339%* | *1,622* | |
| *Steam Maintenance* | *512* | *3* | *2,573,316* | *SG* | *26.884%* | *691,814* | |
| *Hydro Operations* | *535* | *3* | *725,054* | *SG-P* | *26.884%* | *194,925* | |
| *Hydro Operations* | *535* | *3* | *517,813* | *SG-U* | *26.884%* | *139,210* | |
| *Hydro Maintenance* | *545* | *3* | *123,778* | *SG-P* | *26.884%* | *33,277* | |
| *Hydro Maintenance* | *545* | *3* | *36,990* | *SG-U* | *26.884%* | *9,944* | |
| *Other Operations* | *548* | *3* | *614,281* | *SG* | *26.884%* | *165,144* | |
| *Other Operations* | *549* | *3* | *1,108* | *OR* | *Situs* | *1,108* | |
| *Other Maintenance* | *553* | *3* | *145,004* | *SG* | *26.884%* | *38,983* | |
| *Other Power Supply Expenses* | *557* | *3* | *1,615,986* | *SG* | *26.884%* | *434,444* | |
| *Other Power Supply Expenses* | *557* | *3* | *2,570* | *ID* | *Situs* | *-* | |
| *Transmission Operations* | *560* | *3* | *1,403,732* | *SG* | *26.884%* | *377,381* | |
| *Transmission Maintenance* | *571* | *3* | *876,291* | *SG* | *26.884%* | *235,584* | |
| *Distribution Operations* | *580* | *3* | *2,299,609* | *SNPD* | *24.998%* | *574,866* | |
| *Distribution Operations* | *580* | *3* | *1,896,013* | *OR* | *Situs* | *700,490* | |
| *Distribution Maintenance* | *593* | *3* | *481,651* | *SNPD* | *24.998%* | *120,405* | |
| *Distribution Maintenance* | *593* | *3* | *5,106,764* | *OR* | *Situs* | *1,732,535* | |
| *Customer Accounts* | *903* | *3* | *1,506,881* | *CN* | *30.706%* | *462,696* | |
| *Customer Accounts* | *903* | *3* | *545,024* | *OR* | *Situs* | *94,978* | |
| *Customer Services* | *908* | *3* | *261,741* | *CN* | *30.706%* | *80,369* | |
| *Customer Services* | *908* | *3* | *75* | *OTHER* | *0.000%* | *-* | |
| *Customer Services* | *908* | *3* | *332,324* | *OR* | *Situs* | *117,918* | |
| *Administrative & General* | *920* | *3* | *1,496,396* | *SO* | *27.425%* | *410,393* | |
| *Administrative & General* | *920* | *3* | *(2,501)* | *OR* | *Situs* | *(33,236)* | |
| *Administrative & General* | *935* | *3* | *114,469* | *SO* | *27.425%* | *31,394* | |
| *Administrative & General* | *935* | *3* | *6,163* | *OR* | *Situs* | *4,707* | |
| | | | 26,086,786 | | | 7,535,038 | 4.2.11_R |

**Description of Adjustment:**

This adjustment recognizes wage and benefit increases that have occurred, or are projected to occur during the twelve month period ending December 2025 for labor charged to operation & maintenance accounts. See page 4.2.1 for more information on how this adjustment was calculated.

*This adjustment has been updated to reflect corrections for a formulaic error identified, to correct test year AIP calculations, and to update medical escalation of 6% as discussed in the reply testimony of Company witness Sherona L. Cheung.*

**PacifiCorp** Page 4.2.2_R
**Oregon General Rate Case - December 2025**
**Confidential Wage & Employee Benefits**

| Description | Actual 12 Months Ended June 2023 | Pro Forma 12 Months Ending December 2025 | Adjustment | Ref. |
|---|---|---|---|---|
| Regular Ordinary Time | 455,251,586 | 492,738,759 | 37,487,173 | |
| Overtime | 91,478,029 | 99,010,683 | 7,532,654 | |
| Premium Pay | 12,798,107 | 13,851,952 | 1,053,845 | |
| **Subtotal for Escalation** | **559,527,722** | **605,601,394** | **46,073,672** | 4.2.3&4 |
| Unused Leave | 6,470,860 | 7,003,696 | 532,836 | 4.2.5_R |
| Temporary/Contract Labor | - | - | - | |
| Severance Pay | (554,764) | (554,764) | - | 4.2.5_R |
| Other Salary/Labor Costs | 5,272,725 | 5,272,725 | - | |
| Joint Owner Cutbacks | (1,057,432) | (1,144,505) | (87,073) | 4.2.5_R |
| **Subtotal Bare Labor** | **569,659,111** | **616,178,546** | **46,519,435** | |
| Annual Incentive Plan | 30,925,083 | 16,399,774 | (14,525,309) | 4.2.5_R |
| **Total Incentive** | **30,925,083** | **16,399,774** | **(14,525,309)** | |
| Overtime Meals | 1,776,519 | 1,776,519 | - | |
| Bonus and Awards | 2,907,073 | 1,859,817 | (1,047,256) | |
| Physical Exam | 69,612 | 69,612 | - | |
| Education Assistance | 186,812 | 186,812 | - | |
| Mining Salary/Benefit Credit | (176,072) | (176,072) | - | |
| **Total Other Labor** | **4,763,944** | **3,716,688** | **(1,047,256)** | |
| **Subtotal Labor and Incentive** | **605,348,138** | **636,295,008** | **30,946,870** | |
| Pensions | 5,302,118 | 4,231,448 | (1,070,670) | 4.2.6_R |
| SERP Plan | - | - | - | 4.2.6_R |
| Post Retirement Benefits | (458,638) | 1,351,007 | 1,809,645 | 4.2.6_R |
| Post Employment Benefits | 5,194,428 | 4,727,828 | (466,599) | 4.2.6_R |
| **Total Pensions** | **10,037,908** | **10,310,284** | **272,376** | 4.2.6_R |
| Pension Administration | 1,273,267 | 1,277,414 | 4,147 | 4.2.6_R |
| Medical | 57,854,950 | 61,326,247 | 3,471,297 | 4.2.6_R |
| Dental | 3,235,573 | 3,322,933 | 87,360 | 4.2.6_R |
| Vision | 363,698 | 363,698 | 0 | 4.2.6_R |
| Life | 872,318 | 944,148 | 71,830 | 4.2.6_R |
| 401(k) | 45,179,962 | 48,900,254 | 3,720,292 | 4.2.6_R |
| 401(k) Administration | 194 | 181 | (14) | 4.2.6_R |
| Accidental Death & Disability | 28,890 | 31,361 | 2,471 | 4.2.6_R |
| Long-Term Disability | 4,124,560 | 4,478,232 | 353,672 | 4.2.6_R |
| Worker's Compensation | 965,359 | 1,048,472 | 83,113 | 4.2.6_R |
| Other Salary Overhead | 643,291 | 646,517 | 3,226 | 4.2.6_R |
| **Total Benefits** | **114,542,063** | **122,339,457** | **7,797,394** | 4.2.6_R |
| **Subtotal Pensions and Benefits** | **124,579,971** | **132,649,741** | **8,069,771** | 4.2.6_R |
| Payroll Tax Expense | 41,756,669 | 43,961,006 | 2,204,336 | 4.2.7_R |
| Payroll Tax Expense-Unemployment | 3,213,518 | 3,213,518 | - | |
| **Total Payroll Taxes** | **44,970,188** | **47,174,524** | **2,204,336** | |
| **Total Labor** | **774,898,296** | **816,119,274** | **41,220,978** | 4.2.11_R |
| Non-Utility and Capitalized Labor | 284,502,206 | 299,636,397 | 15,134,191 | 4.2.11_R |
| **Total Utility Labor** | **490,396,090** | **516,482,876** | **26,086,786** | 4.2.11_R |

**Ref. 4.2_R**

**PacifiCorp** 
**Oregon General Rate Case - December 2025**
**Confidential Wage & Employee Benefits**

**Composite Labor Increases**

| | | | Ref. |
|---|---|---|---|
| Regular Time/Overtime/Premium Pay - Actual | 559,527,722 | | 4.2.2_R |
| Regular Time/Overtime/Premium Pay Dec 2025 - Pro Forma | 605,601,394 | [1] CAGR | 4.2.2_R |
| % Increase | 8.23% | *3.22%* | |

**Miscellaneous Bare Labor Escalation**

| Description | June 2023 Actual | Pro Forma Increase | December 2025 Pro Forma | Pro Forma Adjustment | Ref. |
|---|---|---|---|---|---|
| Unused Leave | 6,470,860 | 8.23% | 7,003,696 | 532,836 | 4.2.2_R |
| Joint Owner Cutbacks | (1,057,432) | 8.23% | (1,144,505) | (87,073) | 4.2.2_R |
| | 5,413,429 | | 5,859,191 | 445,763 | |

***Bonus and Awards Calculation:***

| *Description* | June 2023 Actual | Pro Forma Increase | December 2025 Pro Forma | Pro Forma Adjustment | Ref. |
|---|---|---|---|---|---|
| Bonus and Awards Calculation | 2,907,073 | | 1,859,817 | **(1,047,256)** | 4.2.2_R |

| Year | [3] *Exempt Bonus* | Non-Exempt and Union Bonus | Total | |
|---|---|---|---|---|
| 2022 | 1,288,716 | 419,961 | 1,708,677 | |
| 2021 | 41,767 | 141,126 | 182,893 | |
| 2020 | 660,585 | 989,763 | 1,650,348 | |
| 2019 | 2,873,088 | 1,026,198 | 3,899,286 | |
| 2018 | 824,535 | 1,033,346 | 1,857,881 | |
| | 5,688,691 | 3,610,394 | 9,299,084 | Total |
| | 1,137,738 | 722,079 | **1,859,817** | 5-Year Avg. |
| | | | **Above** | |

**Annual Incentive Plan Escalation**

| Description | June 2023 Actual | December 2025 | [2] Remove 50% | Pro Forma Adjustment | Ref. |
|---|---|---|---|---|---|
| Annual Incentive Plan Compensation | 30,925,083 | 32,799,548 | 16,399,774 | **(14,525,309)** | 4.2.2_R |

| Year | [3] *Exempt Wages* | [3] *AIP* | % | |
|---|---|---|---|---|
| 2022 | 193,734,722 | 31,894,180 | 16.463% | |
| 2021 | 188,363,246 | 28,389,339 | 15.072% | |
| 2020 | 196,651,699 | 27,916,645 | 14.196% | |
| 2019 | 190,966,807 | 28,914,550 | 15.141% | |
| 2018 | 183,538,498 | 27,045,212 | 14.735% | |
| | 759,520,250 | 112,265,746 | 14.781% | Total |
| 2025 | 221,901,352 | **32,799,548** | 14.781% | 5-Year Avg. |
| | | **Above** | | |

[1] Compound Annual Growth Rate
[2] Per Commission Order in GRC UE-374, Order No. 20-473
[3] *Net of Named Executive Officers (NEO's) Compensation*

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Confidential Wage & Employee Benefits**



| | A | B | C | D | D - A | |
|---|---|---|---|---|---|---|
| **Description** | **Actual June 2023 Net of Joint Venture** | **Actual June 2023 Gross** | **Projected December 2025 Gross** | **Projected December 2025 Net of Joint Venture** | **Pro Forma Adjustment** | **Ref** |
| Pensions | 5,302,118 | 5,388,015 | 4,300,000 | 4,231,448 | **(1,070,670)** | 4.2.2_R |
| SERP Plan | - | - | - | - | **-** | 4.2.2_R |
| Post Retirement Benefits | (454,712) | (413,808) | 1,229,477 | 1,351,007 | **1,805,719** | 4.2.2_R |
| Post Employment Benefits | 5,210,986 | 5,358,850 | 4,861,982 | 4,727,828 | **(483,158)** | 4.2.2_R |
| Subtotal | 10,058,392 | 10,333,057 | 10,391,459 | 10,310,284 | **251,892** | 4.2.2_R |
| Pension Administration | 1,277,414 | 1,313,590 | 1,313,590 | 1,277,414 | **-** | 4.2.2_R |
| Medical | 57,854,950 | 59,531,368 | 63,103,250 | 61,326,247 | **3,471,297** | 4.2.2_R |
| Dental | 3,235,573 | 3,334,059 | 3,424,079 | 3,322,933 | **87,360** | 4.2.2_R |
| Vision | 363,698 | 374,405 | 374,405 | 363,698 | **-** | 4.2.2_R |
| Life | 872,318 | 898,188 | 972,148 | 944,148 | **71,830** | 4.2.2_R |
| 401(k) | 45,179,962 | 46,396,892 | 50,217,392 | 48,900,254 | **3,720,292** | 4.2.2_R |
| 401(k) Administration | 194 | 200 | 186 | 181 | **(14)** | 4.2.2_R |
| Accidental Death & Disability | 28,975 | 29,287 | 31,698 | 31,361 | **2,386** | 4.2.2_R |
| Long-Term Disability | 4,137,531 | 4,254,762 | 4,605,116 | 4,478,232 | **340,700** | 4.2.2_R |
| Worker's Compensation | 968,705 | 994,528 | 1,076,421 | 1,048,472 | **79,767** | 4.2.2_R |
| Other Salary Overhead | 646,517 | 647,276 | 647,276 | 646,517 | **-** | 4.2.2_R |
| Subtotal | 114,565,838 | 117,774,555 | 125,765,561 | 122,339,457 | **7,773,620** | 4.2.2_R |
| Grand Total | **124,624,230** | 128,107,612 | 136,157,020 | **132,649,741** | **8,025,511** | 4.2.2_R |
| | Ref. 4.2.2_R | | | Ref. 4.2.2_R | Ref. 4.2.2_R | |

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Confidential Wage & Employee Benefits**
**Payroll Tax Adjustment Calculation**



| | Line No. | Ref | Social Security | Medicare | Total FICA Tax | Ref |
|---|---|---|---|---|---|---|
| **FICA Calculated on December 2025 Pro Forma Labor** | | | | | | |
| Pro Forma Wages Adjustment | h | | 45,540,837 | 45,540,837 | | 4.2.2_R |
| Pro Forma Incentive Adjustment | i | | (14,525,309) | (14,525,309) | | 4.2.2_R |
| | j | h + i | 31,015,528 | 31,015,528 | | |
| Percentage of eligible wages | k | | 91.25% | 100.00% | | |
| Total eligible wages | l | j * k | 28,300,181 | 31,015,528 | | |
| Tax rate | m | | 6.20% | 1.45% | | |
| Tax on eligible wages | n | l * m | 1,754,611 | 449,725 | | |
| **Total FICA Tax on Pro Forma Labor** | | n | **1,754,611** | **449,725** | **2,204,336** | 4.2.2_R |

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Confidential Wage & Employee Benefits**

| 2020P Indicator | Actual 12 Months Ended June 2023 | % Of Total | Pro Forma Adjustment | Pro Forma 12 Months Ending December 2025 | Oregon Allocation % | Pro Forma Adjustment Oregon Allocated | Pro Forma 12 Months Ending December 2025 Oregon Allocated |
|---|---|---|---|---|---|---|---|
| 500SG | 13,137,646 | 1.6954% | 698,862 | 13,836,508 | 26.884% | 187,883 | 3,719,828 |
| 502SG | 19,916,064 | 2.5702% | 1,059,442 | 20,975,506 | 26.884% | 284,822 | 5,639,088 |
| 503SE | 115,750 | 0.0149% | 6,157 | 121,908 | 26.339% | 1,622 | 32,109 |
| 505SG | 19,410 | 0.0025% | 1,033 | 20,443 | 26.884% | 278 | 5,496 |
| 506SG | 30,844,099 | 3.9804% | 1,640,762 | 32,484,861 | 26.884% | 441,105 | 8,733,281 |
| 510SG | 3,853,094 | 0.4972% | 204,967 | 4,058,061 | 26.884% | 55,104 | 1,090,975 |
| 511SG | 6,962,821 | 0.8985% | 370,390 | 7,333,211 | 26.884% | 99,576 | 1,971,472 |
| 512SG | 24,031,638 | 3.1013% | 1,278,371 | 25,310,009 | 26.884% | 343,679 | 6,804,383 |
| 513SG | 11,584,965 | 1.4950% | 616,266 | 12,201,231 | 26.884% | 165,678 | 3,280,198 |
| 514SG | 1,942,321 | 0.2507% | 103,322 | 2,045,643 | 26.884% | 27,777 | 549,954 |
| 535SG-P | 5,141,090 | 0.6635% | 273,482 | 5,414,572 | 26.884% | 73,523 | 1,455,662 |
| 535SG-U | 4,649,310 | 0.6000% | 247,322 | 4,896,631 | 26.884% | 66,490 | 1,316,418 |
| 536SG-P | 56,973 | 0.0074% | 3,031 | 60,004 | 26.884% | 815 | 16,132 |
| 537SG-P | 628,768 | 0.0811% | 33,448 | 662,215 | 26.884% | 8,992 | 178,031 |
| 537SG-U | 1,068 | 0.0001% | 57 | 1,125 | 26.884% | 15 | 302 |
| 539SG-P | 7,802,656 | 1.0069% | 415,065 | 8,217,721 | 26.884% | 111,587 | 2,209,265 |
| 539SG-U | 5,083,804 | 0.6561% | 270,435 | 5,354,239 | 26.884% | 72,704 | 1,439,442 |
| 540SG-P | 533 | 0.0001% | 28 | 562 | 26.884% | 8 | 151 |
| 542SG-P | 282,649 | 0.0365% | 15,036 | 297,685 | 26.884% | 4,042 | 80,030 |
| 542SG-U | 11,551 | 0.0015% | 614 | 12,165 | 26.884% | 165 | 3,270 |
| 543SG-P | 480,275 | 0.0620% | 25,548 | 505,823 | 26.884% | 6,868 | 135,986 |
| 543SG-U | 301,121 | 0.0389% | 16,018 | 317,139 | 26.884% | 4,306 | 85,260 |
| 544SG-P | 766,343 | 0.0989% | 40,766 | 807,109 | 26.884% | 10,960 | 216,985 |
| 544SG-U | 258,268 | 0.0333% | 13,739 | 272,006 | 26.884% | 3,694 | 73,127 |
| 545SG-P | 797,587 | 0.1029% | 42,428 | 840,015 | 26.884% | 11,406 | 225,831 |
| 545SG-U | 124,415 | 0.0161% | 6,618 | 131,033 | 26.884% | 1,779 | 35,227 |
| 546SG | 10,131 | 0.0013% | 539 | 10,670 | 26.884% | 145 | 2,869 |
| 548SG | 6,710,709 | 0.8660% | 356,978 | 7,067,687 | 26.884% | 95,971 | 1,900,088 |
| 549OR | 20,826 | 0.0027% | 1,108 | 21,934 | Situs | 1,108 | 21,934 |
| 549SG | 4,826,809 | 0.6229% | 256,764 | 5,083,572 | 26.884% | 69,029 | 1,366,676 |
| 552SG | 924,783 | 0.1193% | 49,194 | 973,977 | 26.884% | 13,225 | 261,845 |
| 553SG | 1,710,241 | 0.2207% | 90,977 | 1,801,218 | 26.884% | 24,458 | 484,242 |
| 554SG | 90,852 | 0.0117% | 4,833 | 95,685 | 26.884% | 1,299 | 25,724 |
| 556SG | 589,209 | 0.0760% | 31,343 | 620,552 | 26.884% | 8,426 | 166,830 |
| 557ID | 48,318 | 0.0062% | 2,570 | 50,889 | Situs | - | - |
| 557WYU | - | 0.0000% | - | - | Situs | - | - |
| 557SG | 29,789,128 | 3.8443% | 1,584,643 | 31,373,771 | 26.884% | 426,018 | 8,434,574 |
| 560SG | 10,541,400 | 1.3604% | 560,753 | 11,102,153 | 26.884% | 150,754 | 2,984,720 |
| 561SG | 12,150,429 | 1.5680% | 646,346 | 12,796,776 | 26.884% | 173,765 | 3,440,305 |
| 562SG | 2,881,367 | 0.3718% | 153,275 | 3,034,643 | 26.884% | 41,207 | 815,838 |
| 563SG | 598,310 | 0.0772% | 31,827 | 630,137 | 26.884% | 8,557 | 169,407 |
| 566SG | 98,799 | 0.0127% | 5,256 | 104,055 | 26.884% | 1,413 | 27,974 |
| 567SG | 117,939 | 0.0152% | 6,274 | 124,213 | 26.884% | 1,687 | 33,394 |
| 568SG | 1,504,112 | 0.1941% | 80,012 | 1,584,123 | 26.884% | 21,510 | 425,878 |
| 569SG | 3,264,531 | 0.4213% | 173,658 | 3,438,189 | 26.884% | 46,686 | 924,328 |
| 570SG | 8,332,889 | 1.0754% | 443,271 | 8,776,159 | 26.884% | 119,170 | 2,359,396 |
| 571SG | 3,311,175 | 0.4273% | 176,139 | 3,487,314 | 26.884% | 47,354 | 937,535 |
| 572SG | 60,380 | 0.0078% | 3,212 | 63,592 | 26.884% | 863 | 17,096 |
| 580CA | 877,274 | 0.1132% | 46,667 | 923,941 | Situs | - | - |
| 580ID | 114,755 | 0.0148% | 6,104 | 120,859 | Situs | - | - |
| 580OR | 1,586,945 | 0.2048% | 84,418 | 1,671,364 | Situs | 84,418 | 1,671,364 |
| 580SNPD | 8,785,847 | 1.1338% | 467,366 | 9,253,213 | 24.998% | 116,834 | 2,313,156 |
| 580UT | 460,903 | 0.0595% | 24,518 | 485,420 | Situs | - | - |
| 580WA | 93,833 | 0.0121% | 4,992 | 98,825 | Situs | - | - |
| 580WYP | 106,335 | 0.0137% | 5,657 | 111,992 | Situs | - | - |
| 580WYU | 44,059 | 0.0057% | 2,344 | 46,403 | Situs | - | - |
| 581SNPD | 16,367,477 | 2.1122% | 870,673 | 17,238,150 | 24.998% | 217,654 | 4,309,263 |
| 582CA | 45,954 | 0.0059% | 2,445 | 48,398 | Situs | - | - |
| 582ID | 321,938 | 0.0415% | 17,126 | 339,064 | Situs | - | - |
| 582OR | 412,937 | 0.0533% | 21,966 | 434,904 | Situs | 21,966 | 434,904 |
| 582SNPD | 312 | 0.0000% | 17 | 328 | 24.998% | 4 | 82 |
| 582UT | 1,183,713 | 0.1528% | 62,968 | 1,246,681 | Situs | - | - |

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Confidential Wage & Employee Benefits**

| 2020P Indicator | Actual 12 Months Ended June 2023 | % Of Total | Pro Forma Adjustment | Pro Forma 12 Months Ending December 2025 | Oregon Allocation % | Pro Forma Adjustment Oregon Allocated | Pro Forma 12 Months Ending December 2025 Oregon Allocated |
|---|---|---|---|---|---|---|---|
| 582WA | 49,790 | 0.0064% | 2,649 | 52,439 | Situs | - | - |
| 582WYP | 549,581 | 0.0709% | 29,235 | 578,816 | Situs | - | - |
| 583CA | 660,261 | 0.0852% | 35,123 | 695,384 | Situs | - | - |
| 583ID | 528,614 | 0.0682% | 28,120 | 556,734 | Situs | - | - |
| 583OR | 4,443,618 | 0.5734% | 236,380 | 4,679,998 | Situs | 236,380 | 4,679,998 |
| 583SNPD | - | 0.0000% | - | - | 24.998% | - | - |
| 583UT | 3,808,711 | 0.4915% | 202,606 | 4,011,316 | Situs | - | - |
| 583WA | 392,918 | 0.0507% | 20,901 | 413,819 | Situs | - | - |
| 583WYP | 666,312 | 0.0860% | 35,445 | 701,757 | Situs | - | - |
| 583WYU | 54,856 | 0.0071% | 2,918 | 57,774 | Situs | - | - |
| 585SNPD | 258,639 | 0.0334% | 13,758 | 272,398 | 24.998% | 3,439 | 68,095 |
| 586CA | 88,257 | 0.0114% | 4,695 | 92,952 | Situs | - | - |
| 586ID | 97,875 | 0.0126% | 5,206 | 103,081 | Situs | - | - |
| 586OR | 1,071,052 | 0.1382% | 56,975 | 1,128,027 | Situs | 56,975 | 1,128,027 |
| 586UT | 469,336 | 0.0606% | 24,966 | 494,302 | Situs | - | - |
| 586WA | 177,673 | 0.0229% | 9,451 | 187,124 | Situs | - | - |
| 586WYP | 203,859 | 0.0263% | 10,844 | 214,704 | Situs | - | - |
| 586WYU | 39,863 | 0.0051% | 2,121 | 41,984 | Situs | - | - |
| 587CA | 425,327 | 0.0549% | 22,625 | 447,952 | Situs | - | - |
| 587ID | 878,598 | 0.1134% | 46,737 | 925,336 | Situs | - | - |
| 587OR | 5,553,756 | 0.7167% | 295,434 | 5,849,190 | Situs | 295,434 | 5,849,190 |
| 587UT | 6,098,917 | 0.7871% | 324,434 | 6,423,351 | Situs | - | - |
| 587WA | 1,234,284 | 0.1593% | 65,658 | 1,299,942 | Situs | - | - |
| 587WYP | 1,108,595 | 0.1431% | 58,972 | 1,167,567 | Situs | - | - |
| 587WYU | 107,593 | 0.0139% | 5,723 | 113,316 | Situs | - | - |
| 588CA | 1,254 | 0.0002% | 67 | 1,320 | Situs | - | - |
| 588ID | 139,466 | 0.0180% | 7,419 | 146,885 | Situs | - | - |
| 588OR | 42,474 | 0.0055% | 2,259 | 44,733 | Situs | 2,259 | 44,733 |
| 588SNPD | 17,817,247 | 2.2993% | 947,794 | 18,765,041 | 24.998% | 236,934 | 4,690,961 |
| 588UT | 755,232 | 0.0975% | 40,175 | 795,406 | Situs | - | - |
| 588WA | 17,888 | 0.0023% | 952 | 18,840 | Situs | - | - |
| 588WYP | 229,377 | 0.0296% | 12,202 | 241,579 | Situs | - | - |
| 588WYU | 56,056 | 0.0072% | 2,982 | 59,038 | Situs | - | - |
| 589CA | 16,455 | 0.0021% | 875 | 17,330 | Situs | - | - |
| 589ID | 21,323 | 0.0028% | 1,134 | 22,457 | Situs | - | - |
| 589OR | 57,483 | 0.0074% | 3,058 | 60,541 | Situs | 3,058 | 60,541 |
| 589UT | 246,347 | 0.0318% | 13,104 | 259,451 | Situs | - | - |
| 589WA | 10,116 | 0.0013% | 538 | 10,654 | Situs | - | - |
| 589WYP | 78,303 | 0.0101% | 4,165 | 82,468 | Situs | - | - |
| 589WYU | 12,399 | 0.0016% | 660 | 13,059 | Situs | - | - |
| 590CA | 111,455 | 0.0144% | 5,929 | 117,384 | Situs | - | - |
| 590ID | 47,927 | 0.0062% | 2,550 | 50,477 | Situs | - | - |
| 590OR | 864,307 | 0.1115% | 45,977 | 910,284 | Situs | 45,977 | 910,284 |
| 590SNPD | 2,858,194 | 0.3688% | 152,043 | 3,010,236 | 24.998% | 38,008 | 752,511 |
| 590UT | 824,222 | 0.1064% | 43,845 | 868,067 | Situs | - | - |
| 590WA | 227,075 | 0.0293% | 12,079 | 239,154 | Situs | - | - |
| 590WYP | 222,442 | 0.0287% | 11,833 | 234,275 | Situs | - | - |
| 591SNPD | 2,861 | 0.0004% | 152 | 3,013 | 24.998% | 38 | 753 |
| 592CA | 536,453 | 0.0692% | 28,537 | 564,990 | Situs | - | - |
| 592ID | 477,956 | 0.0617% | 25,425 | 503,381 | Situs | - | - |
| 592OR | 2,412,418 | 0.3113% | 128,329 | 2,540,747 | Situs | 128,329 | 2,540,747 |
| 592SNPD | 2,576,109 | 0.3324% | 137,037 | 2,713,146 | 24.998% | 34,257 | 678,243 |
| 592UT | 1,683,775 | 0.2173% | 89,569 | 1,773,344 | Situs | - | - |
| 592WA | 646,541 | 0.0834% | 34,393 | 680,934 | Situs | - | - |
| 592WYP | 808,312 | 0.1043% | 42,998 | 851,311 | Situs | - | - |
| 593CA | 4,739,724 | 0.6117% | 252,131 | 4,991,856 | Situs | - | - |
| 593ID | 3,988,288 | 0.5147% | 212,158 | 4,200,446 | Situs | - | - |
| 593OR | 23,670,162 | 3.0546% | 1,259,142 | 24,929,305 | Situs | 1,259,142 | 24,929,305 |
| 593SNPD | 2,423,150 | 0.3127% | 128,900 | 2,552,051 | 24.998% | 32,223 | 637,972 |
| 593UT | 23,539,710 | 3.0378% | 1,252,203 | 24,791,913 | Situs | - | - |
| 593WA | 5,191,020 | 0.6699% | 276,138 | 5,467,158 | Situs | - | - |
| 593WYP | 6,158,124 | 0.7947% | 327,583 | 6,485,707 | Situs | - | - |

**PacifiCorp**
**Oregon General Rate Case - December 2025**
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| 2020P Indicator | Actual 12 Months Ended June 2023 | % Of Total | Pro Forma Adjustment | Pro Forma 12 Months Ending December 2025 | Oregon Allocation % | Pro Forma Adjustment Oregon Allocated | Pro Forma 12 Months Ending December 2025 Oregon Allocated |
|---|---|---|---|---|---|---|---|
| 593WYU | 599,279 | 0.0773% | 31,879 | 631,158 | Situs | - | - |
| 594CA | 418,542 | 0.0540% | 22,265 | 440,807 | Situs | - | - |
| 594ID | 549,998 | 0.0710% | 29,257 | 579,256 | Situs | - | - |
| 594OR | 4,939,341 | 0.6374% | 262,750 | 5,202,091 | Situs | 262,750 | 5,202,091 |
| 594SNPD | 7,261 | 0.0009% | 386 | 7,647 | 24.998% | 97 | 1,912 |
| 594UT | 9,749,327 | 1.2581% | 518,619 | 10,267,945 | Situs | - | - |
| 594WA | 1,203,219 | 0.1553% | 64,006 | 1,267,224 | Situs | - | - |
| 594WYP | 596,371 | 0.0770% | 31,724 | 628,096 | Situs | - | - |
| 594WYU | 153,984 | 0.0199% | 8,191 | 162,175 | Situs | - | - |
| 595SNPD | 799,654 | 0.1032% | 42,538 | 842,192 | 24.998% | 10,634 | 210,534 |
| 595WYU | 4,506 | 0.0006% | 240 | 4,745 | Situs | - | - |
| 596CA | 56,276 | 0.0073% | 2,994 | 59,270 | Situs | - | - |
| 596ID | 47,599 | 0.0061% | 2,532 | 50,131 | Situs | - | - |
| 596OR | 518,153 | 0.0669% | 27,563 | 545,717 | Situs | 27,563 | 545,717 |
| 596UT | 141,453 | 0.0183% | 7,525 | 148,977 | Situs | - | - |
| 596WA | 80,433 | 0.0104% | 4,279 | 84,712 | Situs | - | - |
| 596WYP | 236,567 | 0.0305% | 12,584 | 249,151 | Situs | - | - |
| 596WYU | 64,903 | 0.0084% | 3,453 | 68,356 | Situs | - | - |
| 597CA | 12,087 | 0.0016% | 643 | 12,730 | Situs | - | - |
| 597ID | 35,686 | 0.0046% | 1,898 | 37,585 | Situs | - | - |
| 597OR | 139,593 | 0.0180% | 7,426 | 147,018 | Situs | 7,426 | 147,018 |
| 597SNPD | 17,378 | 0.0022% | 924 | 18,303 | 24.998% | 231 | 4,575 |
| 597UT | 213,154 | 0.0275% | 11,339 | 224,493 | Situs | - | - |
| 597WA | 13,559 | 0.0017% | 721 | 14,280 | Situs | - | - |
| 597WYP | 21,758 | 0.0028% | 1,157 | 22,915 | Situs | - | - |
| 597WYU | 8,777 | 0.0011% | 467 | 9,244 | Situs | - | - |
| 598CA | 1,932 | 0.0002% | 103 | 2,035 | Situs | - | - |
| 598OR | 25,327 | 0.0033% | 1,347 | 26,674 | Situs | 1,347 | 26,674 |
| 598SNPD | 369,783 | 0.0477% | 19,671 | 389,454 | 24.998% | 4,917 | 97,357 |
| 598WA | 18,479 | 0.0024% | 983 | 19,462 | Situs | - | - |
| 901CN | 2,282,891 | 0.2946% | 121,439 | 2,404,330 | 30.706% | 37,289 | 738,262 |
| 902CA | 381,995 | 0.0493% | 20,320 | 402,315 | Situs | - | - |
| 902CN | 566,752 | 0.0731% | 30,149 | 596,900 | 30.706% | 9,257 | 183,281 |
| 902ID | 617,716 | 0.0797% | 32,860 | 650,576 | Situs | - | - |
| 902OR | 1,365,793 | 0.1763% | 72,654 | 1,438,447 | Situs | 72,654 | 1,438,447 |
| 902UT | 4,102,727 | 0.5295% | 218,246 | 4,320,973 | Situs | - | - |
| 902WA | 841,816 | 0.1086% | 44,781 | 886,597 | Situs | - | - |
| 902WYP | 823,081 | 0.1062% | 43,784 | 866,865 | Situs | - | - |
| 902WYU | 175,129 | 0.0226% | 9,316 | 184,445 | Situs | - | - |
| 903CA | 29,226 | 0.0038% | 1,555 | 30,781 | Situs | - | - |
| 903CN | 25,477,665 | 3.2879% | 1,355,293 | 26,832,958 | 30.706% | 416,150 | 8,239,202 |
| 903ID | 113,080 | 0.0146% | 6,015 | 119,095 | Situs | - | - |
| 903OR | 419,663 | 0.0542% | 22,324 | 441,987 | Situs | 22,324 | 441,987 |
| 903UT | 1,063,027 | 0.1372% | 56,548 | 1,119,575 | Situs | - | - |
| 903WA | 104,217 | 0.0134% | 5,544 | 109,761 | Situs | - | - |
| 903WYP | 179,029 | 0.0231% | 9,523 | 188,552 | Situs | - | - |
| 903WYU | 29,210 | 0.0038% | 1,554 | 30,764 | Situs | - | - |
| 907CN | - | 0.0000% | - | - | 30.706% | - | - |
| 908CA | - | 0.0000% | - | - | Situs | - | - |
| 908CN | 2,941,885 | 0.3796% | 156,495 | 3,098,379 | 30.706% | 48,052 | 951,374 |
| 908ID | 0 | 0.0000% | 0 | 0 | Situs | - | - |
| 908OR | 2,216,691 | 0.2861% | 117,918 | 2,334,608 | Situs | 117,918 | 2,334,608 |
| 908OTHER | 1,410 | 0.0002% | 75 | 1,485 | 0.000% | - | - |
| 908UT | 2,881,929 | 0.3719% | 153,305 | 3,035,234 | Situs | - | - |
| 908WA | 170,516 | 0.0220% | 9,071 | 179,586 | Situs | - | - |
| 908WYP | 978,104 | 0.1262% | 52,031 | 1,030,134 | Situs | - | - |
| 909CN | 1,978,488 | 0.2553% | 105,246 | 2,083,735 | 30.706% | 32,316 | 639,822 |
| 910CN | - | 0.0000% | - | - | 30.706% | - | - |
| 920ID | - | 0.0000% | - | - | Situs | - | - |
| 920OR | (754,225) | -0.0973% | (40,121) | (794,346) | Situs | (40,121) | (794,346) |
| 920SO | 80,268,539 | 10.3586% | 4,269,912 | 84,538,451 | 27.425% | 1,171,043 | 23,185,064 |
| 920UT | - | 0.0000% | - | - | Situs | - | - |

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Confidential Wage & Employee Benefits**

| 2020P Indicator | Actual 12 Months Ended June 2023 | % Of Total | Pro Forma Adjustment | Pro Forma 12 Months Ending December 2025 | Oregon Allocation % | Pro Forma Adjustment Oregon Allocated | Pro Forma 12 Months Ending December 2025 Oregon Allocated |
|---|---|---|---|---|---|---|---|
| 920WYP | - | 0.0000% | - | - | Situs | - | - |
| 921SO | 41,013 | 0.0053% | 2,182 | 43,195 | 27.425% | 598 | 11,846 |
| 922SO | (24,724,390) | -3.1907% | (1,315,222) | (26,039,612) | 27.425% | (360,706) | (7,141,485) |
| 928CA | 59,356 | 0.0077% | 3,157 | 62,513 | Situs | - | - |
| 928ID | - | 0.0000% | - | - | Situs | - | - |
| 928OR | 129,439 | 0.0167% | 6,886 | 136,325 | Situs | 6,886 | 136,325 |
| 928SO | 230,194 | 0.0297% | 12,245 | 242,439 | 27.425% | 3,358 | 66,490 |
| 928UT | - | 0.0000% | - | - | Situs | - | - |
| 928WA | 327,189 | 0.0422% | 17,405 | 344,594 | Situs | - | - |
| 928WYP | 191,227 | 0.0247% | 10,172 | 201,400 | Situs | - | - |
| 929SO | (27,685,156) | -3.5727% | (1,472,721) | (29,157,877) | 27.425% | (403,901) | (7,996,684) |
| 935CA | 600 | 0.0001% | 32 | 632 | Situs | - | - |
| 935ID | - | 0.0000% | - | - | Situs | - | - |
| 935OR | 88,483 | 0.0114% | 4,707 | 93,190 | Situs | 4,707 | 93,190 |
| 935SO | 2,151,863 | 0.2777% | 114,469 | 2,266,332 | 27.425% | 31,394 | 621,552 |
| 935UT | 24,433 | 0.0032% | 1,300 | 25,732 | Situs | - | - |
| 935WA | 158 | 0.0000% | 8 | 166 | Situs | - | - |
| 935WYP | 2,184 | 0.0003% | 116 | 2,300 | Situs | - | - |
| **Utility Labor** | **490,396,090** | **63.29%** | **26,086,786** | **516,482,876** | | **7,535,038** | **149,183,501** |
| | | | | | | **Ref 4.2_R** | |
| Capital/Non Utility | 284,502,206 | 36.71% | 15,134,191 | 299,636,397 | | | |
| **Total Labor** | **774,898,296** | **100.00%** | **41,220,978** | **816,119,274** | | | |
| | **Ref. 4.2.2_R** | | **Ref. 4.2.2_R** | **Ref. 4.2.2_R** | | | |

**PacifiCorp** PAGE 4.7_R
**Oregon General Rate Case - December 2025**
**Revenue-Sensitive Items & Uncollectible Accounts**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Expense:** | | | | | | | |
| Uncollectible Expense | 904 | 3 | 1,717,034 | OR | Situs | 1,717,034 | 4.7.1_R |
| Other Taxes | 408 | 3 | 6,690,549 | OR | Situs | 6,690,549 | 4.7.1_R |
| *Regulatory Commission Exp* | *928* | *3* | *1,259,216* | *OR* | *Situs* | *1,259,216* | *4.7.1_R* |

**Description of Adjustment:**

This adjusts the Company's actual June 2023 uncollectible accounts expense to the December 2025 pro forma period by applying the unadjusted uncollectible rate (unadjusted uncollectible accounts expense/unadjusted general business revenues) to the normalized level of general business revenues. This adjustment also reflects an impact to other tax expense based on the normalized level of general business revenues and a three year historical average of the tax rates, per Commission Order UE-374.

*This reply adjustment has been updated to reflect OPUC fee percentage updated to .45% as approved in Order No. 24-054, issued February 22, 2024.*

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Revenue Sensitive Items & Uncollectibles**

| | | |
|---|---|---|
| Unadjusted Revenue | 1,399,023,529 | |
| Normalized Revenue | **1,678,849,207** | |
| Adjustments | 279,825,678 | |
| | | |
| Uncollectible Expense in Base Period | 8,584,525 | |
| Uncollectible % | 0.614% | |
| | | |
| **Uncollectible Expense** | **1,717,034** | **4.7_R** |
| | | |
| Franchise Tax % | 2.2761% | **Ref. 4.7.2** |
| Resource Supplier Tax % | 0.1149% | **Ref. 4.7.2** |
| | | |
| **Other Tax Expense** | **6,690,549** | **4.7_R** |
| | | |
| PUC Fees % | 0.4500% | |
| **PUC Fees Expense** | **1,259,216** | **4.7_R** |

**PacifiCorp** PAGE 4.9_R
**Oregon General Rate Case - December 2025**
**Meals and Entertainment Adjustment**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Expense:** | | | | | | | |
| Disallowance Removal | *500* | *1* | *(16,495)* | *SG* | *26.884%* | *(4,434)* | |
| | *502* | *1* | *(4,845)* | *SG* | *26.884%* | *(1,303)* | |
| | 503 | 1 | (18) | SE | 26.339% | (5) | |
| | *506* | *1* | *(39,130)* | *SG* | *26.884%* | *(10,520)* | |
| | *511* | *1* | *(12,823)* | *SG* | *26.884%* | *(3,447)* | |
| | *512* | *1* | *(829)* | *SG* | *26.884%* | *(223)* | |
| | *513* | *1* | *(188)* | *SG* | *26.884%* | *(50)* | |
| | *514* | *1* | *(7,567)* | *SG* | *26.884%* | *(2,034)* | |
| | *535* | *1* | *(618)* | *SG-P* | *26.884%* | *(166)* | |
| | *535* | *1* | *(6,665)* | *SG-U* | *26.884%* | *(1,792)* | |
| | *536* | *1* | *(195)* | *SG-P* | *26.884%* | *(52)* | |
| | *537* | *1* | *(503)* | *SG-P* | *26.884%* | *(135)* | |
| | *537* | *1* | *(151)* | *SG-U* | *26.884%* | *(41)* | |
| | *539* | *1* | *(17,166)* | *SG-P* | *26.884%* | *(4,615)* | |
| | *539* | *1* | *(8,241)* | *SG-U* | *26.884%* | *(2,216)* | |
| | *542* | *1* | *(86)* | *SG-U* | *26.884%* | *(23)* | |
| | *544* | *1* | *(272)* | *SG-P* | *26.884%* | *(73)* | |
| | *545* | *1* | *3,402* | *SG-P* | *26.884%* | *915* | |
| | *545* | *1* | *(147)* | *SG-U* | *26.884%* | *(40)* | |
| | *546* | *1* | *(936)* | *SG* | *26.884%* | *(252)* | |
| | *548* | *1* | *(1,667)* | *SG* | *26.884%* | *(448)* | |
| | *549* | *1* | *(30,964)* | *SG* | *26.884%* | *(8,324)* | |
| | *552* | *1* | *(996)* | *SG* | *26.884%* | *(268)* | |
| | *553* | *1* | *(1,967)* | *SG* | *26.884%* | *(529)* | |
| | *554* | *1* | *(92)* | *SG* | *26.884%* | *(25)* | |
| | *557* | *1* | *(42,957)* | *SG* | *26.884%* | *(11,549)* | |
| | *560* | *1* | *(11,362)* | *SG* | *26.884%* | *(3,054)* | |
| | *561* | *1* | *(3,632)* | *SG* | *26.884%* | *(976)* | |
| | 562 | 1 | (17) | SG | 26.884% | (5) | |
| | *563* | *1* | *(815)* | *SG* | *26.884%* | *(219)* | |
| | *566* | *1* | *(261)* | *SG* | *26.884%* | *(70)* | |
| | *568* | *1* | *(2,507)* | *SG* | *26.884%* | *(674)* | |
| | 569 | 1 | (15) | SG | 26.884% | (4) | |
| | *570* | *1* | *(1,351)* | *SG* | *26.884%* | *(363)* | |
| | *571* | *1* | *(1,481)* | *SG* | *26.884%* | *(398)* | |
| | 572 | 1 | (91) | SG | 26.884% | (24) | |
| | *580* | *1* | *(5,782)* | *OR* | *Situs* | *(5,782)* | |
| | *580* | *1* | *(50,629)* | *SNPD* | *24.998%* | *(12,657)* | |
| | *581* | *1* | *(2,272)* | *SNPD* | *24.998%* | *(568)* | |
| | *583* | *1* | *(17,748)* | *OR* | *Situs* | *(17,748)* | |
| | *585* | *1* | *(234)* | *SNPD* | *24.998%* | *(59)* | |
| | *588* | *1* | *(274)* | *OR* | *Situs* | *(274)* | |
| | *588* | *1* | *(7,243)* | *SNPD* | *24.998%* | *(1,811)* | |
| | | | (297,829) | | | (96,334) | |

**Description of Adjustment:**

This adjustment removes the disallowance that was ordered by the Commission in Order UE 374 No. 20-473. The Commission ruled that all meals and entertainment expenses recognized as discretionary costs and all awards expense would be disallowed at 50%.

*This adjustment includes the removal of an additional dissallowance for Catering Services and On-Site Meals & Refreshments proposed by Staff.*

**PacifiCorp** PAGE 4.9.1_R
**Oregon General Rate Case - December 2025**
**(cont.) Meals and Entertainment Adjustment**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Expense:** | | | | | | | |
| Disallowance Removal | *590* | *1* | *(4,073)* | *OR* | *Situs* | *(4,073)* | |
| | *590* | *1* | *(28,882)* | *SNPD* | *24.998%* | *(7,220)* | |
| | 592 | 1 | (0) | OR | Situs | (0) | |
| | *592* | *1* | *(9,314)* | *SNPD* | *24.998%* | *(2,328)* | |
| | *593* | *1* | *(12,608)* | *OR* | *Situs* | *(12,608)* | |
| | *593* | *1* | *(16,121)* | *SNPD* | *24.998%* | *(4,030)* | |
| | *594* | *1* | *(133)* | *OR* | *Situs* | *(133)* | |
| | *595* | *1* | *(784)* | *SNPD* | *24.998%* | *(196)* | |
| | 597 | 1 | (164) | SNPD | 24.998% | (41) | |
| | *598* | *1* | *(13,175)* | *SNPD* | *24.998%* | *(3,294)* | |
| | *901* | *1* | *(3,467)* | *CN* | *30.706%* | *(1,065)* | |
| | *902* | *1* | *(891)* | *CN* | *30.706%* | *(274)* | |
| | *902* | *1* | *(9)* | *OR* | *Situs* | *(9)* | |
| | *903* | *1* | *(10,084)* | *CN* | *30.706%* | *(3,096)* | |
| | 903 | 1 | (0) | OR | Situs | (0) | |
| | *908* | *1* | *(8,545)* | *CN* | *30.706%* | *(2,624)* | |
| | *908* | *1* | *(9,147)* | *OR* | *Situs* | *(9,147)* | |
| | *909* | *1* | *(2,841)* | *CN* | *30.706%* | *(872)* | |
| | *921* | *1* | *(1)* | *OR* | *Situs* | *(1)* | |
| | *921* | *1* | *(288,107)* | *SO* | *27.425%* | *(79,015)* | |
| | 925 | 1 | (65) | SO | 27.425% | (18) | |
| | 929 | 1 | 138 | SO | 27.425% | 38 | |
| | *935* | *1* | *(460)* | *SO* | *27.425%* | *(126)* | |
| | *542* | *1* | *(28)* | *SG-P* | *26.884%* | *(8)* | |
| | *543* | *1* | *(45)* | *SG-P* | *26.884%* | *(12)* | |
| | *543* | *1* | *147* | *SG-U* | *26.884%* | *40* | |
| | *582* | *1* | *(255)* | *OR* | *Situs* | *(255)* | |
| | *910* | *1* | *(1,134)* | *CN* | *30.706%* | *(348)* | |
| | | | (410,049) | | | (130,714) | |
| Total Adjustment | | | (707,878) | | | (227,049) | |

**Description of Adjustment:**

This adjustment removes the disallowance that was ordered by the Commission in Order UE 374 No. 20-473. The Commission ruled that all meals and entertainment expenses recognized as discretionary costs and all awards expense would be disallowed at 50%.

*This adjustment includes the removal of an additional disallowance for Catering Services and On-Site Meals & Refreshments proposed by Staff.*

**PacifiCorp**
**Oregon General Rate Case - December 2023**
**Meals & Entertainment Adjustment**
**Summary of Adjustments - Incremental Rebuttal**



**503115 - On-site Meals & Refreshment**

| FERC Account | Allocation | Amount |
|---|---|---|
| 500 | SG | 30,819 |
| 502 | SG | 5,111 |
| 505 | SG | - |
| 506 | SG | 54,038 |
| 511 | SG | 5,013 |
| 512 | SG | 790 |
| 513 | SG | 213 |
| 514 | SG | 283 |
| 535 | SG-P | 177 |
| 535 | SG-U | 2,488 |
| 536 | SG-P | 192 |
| 537 | SG-P | 686 |
| 537 | SG-U | 24 |
| 539 | SG-P | 24,138 |
| 539 | SG-U | 7,211 |
| 542 | SG-P | 56 |
| 542 | SG-U | 77 |
| 543 | SG-P | 90 |
| 543 | SG-U | (295) |
| 544 | SG-P | 132 |
| 545 | SG-P | (8,393) |
| 545 | SG-U | 37 |
| 546 | SG | 1,766 |
| 548 | SG | 1,398 |
| 549 | OR | - |
| 549 | SG | 19,666 |
| 552 | SG | 629 |
| 553 | SG | 2,084 |
| 554 | SG | 162 |
| 557 | SG | 14,224 |
| 560 | SG | 3,757 |
| 561 | SG | 2,872 |
| 563 | SG | 96 |
| 566 | SG | 72 |
| 568 | SG | 2,091 |
| 569 | SG | - |
| 570 | SG | 796 |
| 571 | SG | 332 |
| 580 | OR | 237 |
| 580 | SNPD | 19,423 |
| 581 | SNPD | 2,432 |
| 582 | OR | 510 |
| 583 | OR | 29,190 |
| 585 | SNPD | 225 |
| 588 | OR | 427 |
| 588 | SNPD | 1,804 |
| 590 | OR | 185 |
| 590 | SNPD | 25,749 |
| 592 | OR | - |
| 592 | SNPD | 5,547 |
| 593 | OR | 11,115 |
| 593 | SNPD | 4,183 |
| 594 | OR | 28 |
| 595 | SNPD | 602 |
| 598 | SNPD | 25,357 |
| 901 | CN | 2,271 |
| 902 | CN | 367 |
| 902 | OR | 14 |
| 903 | CN | 10,907 |
| 903 | OR | - |
| 908 | CN | 5,191 |
| 908 | OR | 1,987 |
| 909 | CN | 1,725 |
| 910 | CN | 2,268 |
| 921 | OR | 1 |
| 921 | SO | 37,238 |
| 935 | SO | 796 |
| Grand Total | | 362,609 |

| | | |
|---|---|---|
| On-Site Meals & Rfrsh. | 362,609 | **Above** |
| Disallowance | -50% | |
| Removal | (181,304) | |
| | | |
| Catering Services | 11,459 | **Ref 4.9.4_R** |
| Disallowance | -50% | |
| | (5,729) | |
| | | |
| **Total Disallowance** | **(187,034)** | **Ref. 4.9_R** |

**PacifiCorp**
**Oregon General Rate Case - December 2023**
**Meals & Entertainment Adjustment**
**Summary of Adjustments - Incremental Rebuttal**

**530035 - Catering Services-Non Employees**

| FERC Account | Allocation | Amount |
|---|---|---|
| 502 | SG | (0) |
| 505 | SG | (0) |
| 506 | SG | (2,885) |
| 511 | SG | 12,756 |
| 514 | SG | 1,589 |
| Grand Total | | 11,459 |

**PacifiCorp** PAGE 4.10_R
**Oregon General Rate Case - December 2025**
**O&M Escalation**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Expense:** | | | | | | | |
| *Steam Operations* | *500* | *3* | *72,324* | *SG* | *26.884%* | *19,444* | |
| *Steam Operations* | *500* | *3* | *(798)* | *SG* | *26.884%* | *(215)* | |
| Steam Operations | 501 | 3 | 1,074,003 | SE | 26.339% | 282,883 | |
| *Steam Operations* | *502* | *3* | *2,825,530* | *SG* | *26.884%* | *759,620* | |
| *Steam Operations* | *503* | *3* | *(5,600)* | *SE* | *26.339%* | *(1,475)* | |
| Steam Operations | 505 | 3 | 33,794 | SG | 26.884% | 9,085 | |
| *Steam Operations* | *506* | *3* | *(318,626)* | *SG* | *26.884%* | *(85,660)* | |
| *Steam Operations* | *506* | *3* | *232,168* | *SG* | *26.884%* | *62,416* | |
| Steam Operations | 507 | 3 | (10,415) | SG | 26.884% | (2,800) | |
| Steam Maintenance | 510 | 3 | 6,221 | SG | 26.884% | 1,673 | |
| *Steam Maintenance* | *510* | *3* | *3,584* | *SG* | *26.884%* | *964* | |
| *Steam Maintenance* | *511* | *3* | *48,989* | *SG* | *26.884%* | *13,170* | |
| *Steam Maintenance* | *512* | *3* | *(190,575)* | *SG* | *26.884%* | *(51,234)* | |
| *Steam Maintenance* | *512* | *3* | *194,582* | *SG* | *26.884%* | *52,312* | |
| *Steam Maintenance* | *513* | *3* | *(1)* | *SG* | *26.884%* | *(0)* | |
| *Steam Maintenance* | *513* | *3* | *78,579* | *SG* | *26.884%* | *21,125* | |
| *Steam Maintenance* | *514* | *3* | *38,878* | *SG* | *26.884%* | *10,452* | |
| *Hydro Operations* | *535* | *3* | *65,587* | *SG-P* | *26.884%* | *17,633* | |
| *Hydro Operations* | *535* | *3* | *(23,041)* | *SG-U* | *26.884%* | *(6,194)* | |
| Hydro Operations | 535 | 3 | (39,160) | SG | 26.884% | (10,528) | |
| *Hydro Operations* | *536* | *3* | *7,613* | *SG-P* | *26.884%* | *2,047* | |
| *Hydro Operations* | *537* | *3* | *65,129* | *SG-P* | *26.884%* | *17,509* | |
| Hydro Operations | 537 | 3 | 6,353 | SG-U | 26.884% | 1,708 | |
| *Hydro Operations* | *539* | *3* | *131,296* | *SG-P* | *26.884%* | *35,298* | |
| *Hydro Operations* | *539* | *3* | *53,687* | *SG-U* | *26.884%* | *14,433* | |
| *Hydro Operations* | *539* | *3* | *(154)* | *SG* | *26.884%* | *(41)* | |
| Hydro Operations | 540 | 3 | 32,826 | SG-P | 26.884% | 8,825 | |
| Hydro Operations | 540 | 3 | (2,490) | SG-U | 26.884% | (669) | |
| Hydro Maintenance | 541 | 3 | (5) | SG-P | 26.884% | (1) | |
| Hydro Maintenance | 542 | 3 | (1,323) | SG-P | 26.884% | (356) | |
| Hydro Maintenance | 542 | 3 | (30) | SG-U | 26.884% | (8) | |
| Hydro Maintenance | 543 | 3 | (1,322) | SG-P | 26.884% | (355) | |
| Hydro Maintenance | 543 | 3 | (599) | SG-U | 26.884% | (161) | |
| Hydro Maintenance | 544 | 3 | (2,017) | SG-P | 26.884% | (542) | |
| Hydro Maintenance | 544 | 3 | (248) | SG-U | 26.884% | (67) | |
| *Hydro Maintenance* | *545* | *3* | *(7,373)* | *SG-P* | *26.884%* | *(1,982)* | |
| Hydro Maintenance | 545 | 3 | (2,334) | SG-U | 26.884% | (627) | |
| Hydro Maintenance | 545 | 3 | (0) | SG | 26.884% | (0) | |
| Other Operations | 546 | 3 | 21,608 | SG | 26.884% | 5,809 | |
| *Other Operations* | *546* | *3* | *(41)* | *SG* | *26.884%* | *(11)* | |
| *Other Operations* | *548* | *3* | *(73)* | *SG* | *26.884%* | *(20)* | |
| | | | 4,386,525 | | | 1,173,457 | |

**Description of Adjustment:**

This adjustment calculates the non-labor O&M escalation from June 2023 to December 2025 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2023 actual data was separated into labor and non-labor components and costs that should not be included in June 2023 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

*This adjustment has been updated to incorporate spillover impacts from updates to other O&M adjustments made in Reply.*

**PacifiCorp** PAGE 4.10.1_R
**Oregon General Rate Case - December 2025**
**(cont.) O&M Escalation**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Expense:** | | | | | | | |
| *Other Operations* | *548* | *3* | *721,341* | *SG* | *26.884%* | *193,926* | |
| *Other Operations* | *548* | *3* | *17,531* | *SG* | *26.884%* | *4,713* | |
| Other Operations | 549 | 3 | 522 | OR | Situs | 522 | |
| *Other Operations* | *549* | *3* | *(3,313)* | *SG* | *26.884%* | *(891)* | |
| *Other Operations* | *549* | *3* | *(1,032)* | *SG* | *26.884%* | *(277)* | |
| *Other Operations* | *549* | *3* | *257,731* | *SG-W* | *26.884%* | *69,289* | |
| Other Operations | 550 | 3 | 16,357 | OR | Situs | 16,357 | |
| Other Operations | 550 | 3 | 1,742 | SG | 26.884% | 468 | |
| Other Operations | 550 | 3 | 464,856 | SG-W | 26.884% | 124,973 | |
| *Other Maintenance* | *552* | *3* | *(24)* | *SG* | *26.884%* | *(6)* | |
| *Other Maintenance* | *552* | *3* | *36,051* | *SG* | *26.884%* | *9,692* | |
| *Other Maintenance* | *552* | *3* | *1,735* | *SG* | *26.884%* | *466* | |
| *Other Maintenance* | *553* | *3* | *40,991* | *SG* | *26.884%* | *11,020* | |
| *Other Maintenance* | *553* | *3* | *427,932* | *SG-W* | *26.884%* | *115,046* | |
| *Other Maintenance* | *553* | *3* | *46,355* | *SG* | *26.884%* | *12,462* | |
| Other Maintenance | 553 | 3 | 5,400 | SG | 26.884% | 1,452 | |
| *Other Maintenance* | *554* | *3* | *(2)* | *SG* | *26.884%* | *(1)* | |
| Other Maintenance | 554 | 3 | 42,193 | SG-W | 26.884% | 11,343 | |
| Other Maintenance | 554 | 3 | 51,589 | SG | 26.884% | 13,869 | |
| Other Maintenance | 554 | 3 | 1,860 | SG | 26.884% | 500 | |
| *Other Operations* | *556* | *3* | *83,758* | *SG* | *26.884%* | *22,518* | |
| Other Operations | 557 | 3 | 499,125 | OR | Situs | 340,179 | |
| *Other Operations* | *557* | *3* | *199,410* | *SG* | *26.884%* | *53,610* | |
| Other Operations | 557 | 3 | 269 | SE | 26.339% | 71 | |
| *Transmission Operations* | *560* | *3* | *(8)* | *SG* | *26.884%* | *(2)* | |
| *Transmission Operations* | *560* | *3* | *267* | *SG* | *26.884%* | *72* | |
| Transmission Operations | 561 | 3 | 4,567 | SG | 26.884% | 1,228 | |
| *Transmission Operations* | *561* | *3* | *(2)* | *SG* | *26.884%* | *(1)* | |
| Transmission Operations | 562 | 3 | (0) | SG | 26.884% | (0) | |
| Transmission Operations | 562 | 3 | 1,246 | SG | 26.884% | 335 | |
| Transmission Operations | 563 | 3 | (1) | SG | 26.884% | (0) | |
| Transmission Operations | 563 | 3 | 810 | SG | 26.884% | 218 | |
| Transmission Operations | 566 | 3 | 2,663 | SG | 26.884% | 716 | |
| Transmission Operations | 566 | 3 | (0) | SG | 26.884% | (0) | |
| Transmission Operations | 567 | 3 | 1,546 | SG | 26.884% | 416 | |
| *Transmission Maintenance* | *568* | *3* | *82* | *SG* | *26.884%* | *22* | |
| *Transmission Maintenance* | *568* | *3* | *7,104* | *SG* | *26.884%* | *1,910* | |
| Transmission Maintenance | 569 | 3 | 0 | SG | 26.884% | 0 | |
| | | | 2,930,650 | | | 1,006,214 | |

**Description of Adjustment:**

This adjustment calculates the non-labor O&M escalation from June 2023 to December 2025 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2023 actual data was separated into labor and non-labor components and costs that should not be included in June 2023 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

*This adjustment has been updated to incorporate spillover impacts from updates to other O&M adjustments made in Reply.*

**PacifiCorp** PAGE 4.10.2_R
**Oregon General Rate Case - December 2025**
**(cont.) O&M Escalation**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Expense:** | | | | | | | |
| *Transmission Maintenance* | *569* | *3* | *(96,993)* | *SG* | *26.884%* | *(26,076)* | |
| *Transmission Maintenance* | *570* | *3* | *(187,492)* | *SG* | *26.884%* | *(50,406)* | |
| *Transmission Maintenance* | *570* | *3* | *44* | *SG* | *26.884%* | *12* | |
| *Transmission Maintenance* | *571* | *3* | *(409,807)* | *SG* | *26.884%* | *(110,173)* | |
| *Transmission Maintenance* | *571* | *3* | *299,540* | *SG* | *26.884%* | *80,529* | |
| Transmission Maintenance | 572 | 3 | 3 | SG | 26.884% | 1 | |
| Transmission Maintenance | 572 | 3 | (3,438) | SG | 26.884% | (924) | |
| Transmission Maintenance | 573 | 3 | (3,219) | SG | 26.884% | (865) | |
| *Distribution Operations* | *580* | *3* | *4,729* | *OR* | *Situs* | *(3,969)* | |
| *Distribution Operations* | *580* | *3* | *123,104* | *SNPD* | *24.998%* | *30,774* | |
| *Distribution Operations* | *581* | *3* | *(2,054)* | *SNPD* | *24.998%* | *(513)* | |
| *Distribution Operations* | *582* | *3* | *56,427* | *OR* | *Situs* | *14,602* | |
| Distribution Operations | 582 | 3 | 4 | SNPD | 24.998% | 1 | |
| *Distribution Operations* | *583* | *3* | *11,074* | *OR* | *Situs* | *(42,019)* | |
| *Distribution Operations* | *585* | *3* | *574* | *SNPD* | *24.998%* | *144* | |
| *Distribution Operations* | *586* | *3* | *11,783* | *OR* | *Situs* | *5,376* | |
| *Distribution Operations* | *587* | *3* | *119,938* | *OR* | *Situs* | *35,518* | |
| *Distribution Operations* | *588* | *3* | *14,885* | *OR* | *Situs* | *(7,118)* | |
| *Distribution Operations* | *588* | *3* | *(376,055)* | *SNPD* | *24.998%* | *(94,008)* | |
| *Distribution Operations* | *589* | *3* | *51,352* | *OR* | *Situs* | *37,687* | |
| Distribution Operations | 589 | 3 | 8,427 | SNPD | 24.998% | 2,107 | |
| *Distribution Maintenance* | *590* | *3* | *334,385* | *OR* | *Situs* | *(5,373)* | |
| *Distribution Maintenance* | *590* | *3* | *(14,620)* | *SNPD* | *24.998%* | *(3,655)* | |
| Distribution Maintenance | 591 | 3 | (91,139) | OR | Situs | (30,417) | |
| Distribution Maintenance | 591 | 3 | (3,560) | SNPD | 24.998% | (890) | |
| *Distribution Maintenance* | *592* | *3* | *(112,509)* | *OR* | *Situs* | *(38,033)* | |
| *Distribution Maintenance* | *592* | *3* | *71,888* | *SNPD* | *24.998%* | *17,971* | |
| *Distribution Maintenance* | *593* | *3* | *(419,333)* | *OR* | *Situs* | *1,000,541* | |
| *Distribution Maintenance* | *593* | *3* | *(37,510)* | *SNPD* | *24.998%* | *(9,377)* | |
| *Distribution Maintenance* | *594* | *3* | *(1,003,117)* | *OR* | *Situs* | *(195,499)* | |
| Distribution Maintenance | 594 | 3 | (94) | SNPD | 24.998% | (23) | |
| Distribution Maintenance | 595 | 3 | 199 | OR | Situs | - | |
| *Distribution Maintenance* | *595* | *3* | *(11,308)* | *SNPD* | *24.998%* | *(2,827)* | |
| *Distribution Maintenance* | *596* | *3* | *(53,205)* | *OR* | *Situs* | *(11,248)* | |
| *Distribution Maintenance* | *597* | *3* | *(6,410)* | *OR* | *Situs* | *(1,442)* | |
| Distribution Maintenance | 597 | 3 | 2,043 | SNPD | 24.998% | 511 | |
| Distribution Maintenance | 598 | 3 | (93,488) | OR | Situs | (29,566) | |
| *Distribution Maintenance* | *598* | *3* | *(141,921)* | *SNPD* | *24.998%* | *(35,478)* | |
| Customer Accounts Operations | 901 | 3 | 12 | OR | Situs | - | |
| | | | (1,956,862) | | | 525,875 | |

**Description of Adjustment:**

This adjustment calculates the non-labor O&M escalation from June 2023 to December 2025 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2023 actual data was separated into labor and non-labor components and costs that should not be included in June 2023 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

*This adjustment has been updated to incorporate spillover impacts from updates to other O&M adjustments made in Reply.*

**PacifiCorp** PAGE 4.10.3_R
**Oregon General Rate Case - December 2025**
**(cont.) O&M Escalation**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Expense:** | | | | | | | |
| *Customer Accounts Operations* | *901* | *3* | *17,582* | *CN* | *30.706%* | *5,399* | |
| *Customer Accounts Operations* | *902* | *3* | *72,535* | *OR* | *Situs* | *16,080* | |
| *Customer Accounts Operations* | *902* | *3* | *4,117* | *CN* | *30.706%* | *1,264* | |
| *Customer Accounts Operations* | *903* | *3* | *27,209* | *OR* | *Situs* | *4,142* | |
| *Customer Accounts Operations* | *903* | *3* | *339,552* | *CN* | *30.706%* | *104,261* | |
| Customer Accounts Operations | 904 | 3 | 628,327 | OR | Situs | 216,916 | |
| Customer Accounts Operations | 904 | 3 | (23,150) | CN | 30.706% | (7,108) | |
| Customer Accounts Operations | 905 | 3 | 6 | OR | Situs | (0) | |
| Customer Accounts Operations | 905 | 3 | 4 | CN | 30.706% | 1 | |
| Customer Service Operations | 907 | 3 | (11) | CN | 30.706% | (3) | |
| *Customer Service Operations* | *908* | *3* | *(7,610)* | *OR* | *Situs* | *(1,234)* | |
| *Customer Service Operations* | *908* | *3* | *(2,310)* | *CN* | *30.706%* | *(709)* | |
| Customer Service Operations | 908 | 3 | (1,239,877) | OTHER | 0.000% | - | |
| Customer Service Operations | 909 | 3 | (21,508) | OR | Situs | (7,141) | |
| *Customer Service Operations* | *909* | *3* | *(9,449)* | *CN* | *30.706%* | *(2,901)* | |
| *Customer Service Operations* | *910* | *3* | *(68)* | *CN* | *30.706%* | *(21)* | |
| *A&G Operations* | *920* | *3* | *46,441* | *OR* | *Situs* | *46,437* | |
| *A&G Operations* | *920* | *3* | *44,375* | *SO* | *27.425%* | *12,170* | |
| A&G Operations | 921 | 3 | 1,912 | CN | 30.706% | 587 | |
| A&G Operations | 921 | 3 | 7,830 | OR | Situs | (66) | |
| *A&G Operations* | *921* | *3* | *265,034* | *SO* | *27.425%* | *72,687* | |
| *A&G Operations* | *922* | *3* | *(1,309,375)* | *SO* | *27.425%* | *(359,102)* | |
| A&G Operations | 923 | 3 | 167,212 | OR | Situs | 48,050 | |
| A&G Operations | 923 | 3 | 2,896,718 | SO | 27.425% | 794,438 | |
| A&G Operations | 928 | 3 | 125,499 | SG | 26.884% | 33,739 | |
| *A&G Operations* | *928* | *3* | *28,713* | *SO* | *27.425%* | *7,875* | |
| *A&G Operations* | *928* | *3* | *363,731* | *OR* | *Situs* | *130,824* | |
| *A&G Operations* | *929* | *3* | *942,300* | *SO* | *27.425%* | *258,430* | |
| *A&G Operations* | *930* | *3* | *62,999* | *OR* | *Situs* | *70,007* | |
| A&G Operations | 930 | 3 | (122,357) | SO | 27.425% | (33,557) | |
| A&G Operations | 931 | 3 | 27,072 | OR | Situs | 21,016 | |
| A&G Operations | 931 | 3 | (272,614) | SO | 27.425% | (74,766) | |
| A&G Operations | 935 | 3 | (371) | OR | Situs | (133) | |
| A&G Operations | 935 | 3 | (24) | CN | 30.706% | (8) | |
| A&G Operations | 935 | 3 | (18,720) | SO | 27.425% | (5,134) | |
| | | | 3,041,723 | | | 1,352,440 | |
| | | | 4,386,525 | | | 1,173,457 | 4.10_R |
| | | | 2,930,650 | | | 1,006,214 | 4.10.1_R |
| | | | (1,956,862) | | | 525,875 | 4.10.2_R |
| | | | 3,041,723 | | | 1,352,440 | 4.10.3_R |
| Total Adjustment | | | 8,402,036 | | | 4,057,985 | |

**Description of Adjustment:**

This adjustment calculates the non-labor O&M escalation from June 2023 to December 2025 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2023 actual data was separated into labor and non-labor components and costs that should not be included in June 2023 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

*This adjustment has been updated to incorporate spillover impacts from updates to other O&M adjustments made in Reply.*

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**O&M Expense Escalation**
**12 Months Ending December 2025**

| Function | Allocation Code | Unadjusted O&M | 4.1 Miscellaneous General Expense & Revenue | 4.2_R Remove Unadjusted Wages & Employee Benefits | 4.4 Remove Non-Recurring Entries | 4.5 Insurance Expense | 4.6 Generation Overhaul Expense | 4.8 Membership & Subscriptions | 4.9_R Meals and Entertainment Adjustment | 4.11 Wildfire & Veg Management Expenses | 4.13 Incremental O&M |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Steam Operation | | | | | | | | | | | |
| | NPCID | 87,693 | - | - | - | - | - | - | - | - | - |
| | NPCSE | 612,767,769 | - | - | - | - | - | - | - | - | - |
| | NPCSSECH | - | - | - | - | - | - | - | - | - | - |
| | NPCWYP | 253,319 | - | - | - | - | - | - | - | - | - |
| | SE | 22,201,079 | - | (115,750) | - | - | - | - | (18) | - | - |
| | SG | 92,961,108 | (8,333) | (33,053,710) | - | - | - | - | (43,975) | - | - |
| | SNPPS | 36,145,995 | - | (30,863,509) | - | - | - | - | - | - | - |
| | SSECH | - | - | - | - | - | - | - | - | - | - |
| | SSGCH | - | - | - | - | - | - | - | (16,495) | - | - |
| | CA | - | - | - | - | - | - | - | - | - | - |
| | ID | - | - | - | - | - | - | - | - | - | - |
| | OR | - | - | - | - | - | - | - | - | - | - |
| | WA | - | - | - | - | - | - | - | - | - | - |
| | WYP | - | - | - | - | - | - | - | - | - | - |
| | **Steam Operation Total** | 764,416,963 | (8,333) | (64,032,969) | - | - | - | - | (60,488) | - | - |
| Steam Maintenance | | | | | | | | | | | |
| | SG | 37,046,165 | - | (8,905,142) | - | - | 1,991,017 | - | (21,406) | - | (60,990,000) |
| | SNPPS | 128,038,140 | - | (39,469,697) | - | - | - | - | - | - | - |
| | SSGCH | - | - | - | - | - | - | - | - | - | - |
| | **Steam Maintenance Total** | 165,084,305 | - | (48,374,839) | - | - | 1,991,017 | - | (21,406) | - | (60,990,000) |
| Hydro Operations | | | | | | | | | | | |
| | SG-P | 30,238,570 | - | (13,630,020) | - | - | - | - | (18,482) | - | (402,900) |
| | SG-U | 11,587,864 | - | (9,734,182) | - | - | - | - | (6,816) | - | - |
| | SG | - | - | - | - | - | - | - | (8,241) | - | - |
| | **Hydro Operations Total** | 41,826,434 | - | (23,364,202) | - | - | - | - | (33,540) | - | (402,900) |
| Hydro Maintenance | | | | | | | | | | | |
| | SG-P | 6,426,681 | - | (2,326,854) | - | - | - | - | 3,057 | - | - |
| | SG-U | 1,789,755 | - | (695,354) | - | - | - | - | (86) | - | - |
| | SG | (7,385,140) | - | - | 7,385,140 | - | - | - | - | - | - |
| | **Hydro Maintenance Total** | 831,296 | - | (3,022,208) | 7,385,140 | - | - | - | 2,972 | - | - |
| Purchased Power | | | | | | | | | | | |
| | NPCSE | 20,074,007 | - | - | - | - | - | - | - | - | - |
| | NPCSG | 1,207,781,184 | - | - | - | - | - | - | - | - | - |
| | NPCCA | 2,514 | - | - | - | - | - | - | - | - | - |
| | NPCOR | 80,131 | - | - | - | - | - | - | - | - | - |
| | NPCUT | 13,361,355 | - | - | - | - | - | - | - | - | - |
| | OTHER | (519,795,484) | - | - | - | - | - | - | - | - | - |
| | **Purchase Power Total** | 721,503,708 | - | - | - | - | - | - | - | - | - |
| Other Operations | | | | | | | | | | | |
| | NPCSE | 621,099,417 | - | - | - | - | - | - | - | - | - |
| | NPCSSECT | 628,119 | - | - | - | - | - | - | - | - | - |
| | SG-W | 17,220,851 | - | (682,085) | - | - | - | - | - | - | - |
| | SNPPO | 27,406,981 | - | (10,385,911) | - | - | - | - | - | - | - |
| | SSGCT | 880,908 | - | (479,653) | - | - | - | - | - | - | - |
| | SE | 6,158 | - | - | - | - | - | - | - | - | - |
| | SG | 35,946,961 | 955,548 | (30,378,337) | - | - | - | - | (76,524) | - | - |
| | ID | 3,589,393 | - | (48,318) | - | - | - | - | - | - | - |
| | OR | 8,193,280 | - | (20,826) | - | - | - | - | - | - | - |
| | UT | 35,000 | - | - | - | - | - | - | - | - | - |
| | WYU | 61,932 | - | - | - | - | - | - | - | - | - |
| | **Other Operations Total** | 715,068,999 | 955,548 | (41,995,131) | - | - | - | - | (76,524) | - | - |
| Other Maintenance | | | | | | | | | | | |
| | SNPPO | 7,916,295 | - | (2,296,764) | - | - | - | - | - | - | - |
| | SSGCT | 539,246 | - | (162,047) | - | - | - | - | - | - | - |
| | SG | - | - | - | - | - | 2,833,691 | - | (3,055) | - | - |
| | SG-W | 19,983,385 | - | (267,064) | - | - | - | - | - | - | - |
| | **Other Maintenance Total** | 28,438,926 | - | (2,725,876) | - | - | 2,833,691 | - | (3,055) | - | - |
| Transmission Operations | | | | | | | | | | | |
| | NPCSE | 25,912,615 | - | - | - | - | - | - | - | - | - |
| | NPCSG | 141,048,505 | - | - | - | - | - | - | - | - | - |
| | SG | - | - | - | - | - | - | - | (16,087) | - | - |
| | SNPT | 42,554,838 | - | (26,388,246) | - | - | - | - | - | - | - |
| | **Transmission Operations Total** | 209,515,958 | - | (26,388,246) | - | - | - | - | (16,087) | - | - |
| Transmission Maintenance | | | | | | | | | | | |
| | SNPT | 37,660,999 | - | (16,473,086) | - | - | - | - | - | - | - |
| | SG | - | - | - | - | - | - | - | (5,444) | (9,145,557) | - |
| | **Transmission Maintenance Total** | 37,660,999 | - | (16,473,086) | - | - | - | - | (5,444) | (9,145,557) | - |



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**PacifiCorp**
**Oregon General Rate Case - December 2025**
**O&M Expense Escalation**
**12 Months Ending December 2025**

| Function | Allocation Code | Unadjusted O&M | 4.1 Miscellaneous General Expense & Revenue | 4.2_R Remove Unadjusted Wages & Employee Benefits | 4.4 Remove Non-Recurring Entries | 4.5 Insurance Expense | 4.6 Generation Overhaul Expense | 4.8 Membership & Subscriptions | 4.9_R Meals and Entertainment Adjustment | 4.11 Wildfire & Veg Management Expenses | 4.13 Incremental O&M |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Distribution Operations | | | | | | | | | | | |
| | CA | 2,057,158 | - | (2,114,781) | - | - | - | - | - | - | - |
| | ID | 2,935,411 | - | (2,102,569) | - | - | - | - | - | - | - |
| | OR | 15,077,850 | - | (13,168,266) | - | - | - | - | (24,059) | - | - |
| | SNPD | 31,716,436 | - | (43,229,522) | - | - | - | - | (60,379) | - | - |
| | UT | 20,645,775 | - | (13,023,157) | - | - | - | - | - | - | - |
| | WA | 2,517,728 | - | (1,976,502) | - | - | - | - | - | - | - |
| | WYP | 4,772,316 | - | (2,942,362) | - | - | - | - | - | - | - |
| | WYU | 371,755 | - | (314,827) | - | - | - | - | - | - | - |
| | **Distribution Operations Total** | 80,094,429 | - | (78,871,987) | - | - | - | - | (84,437) | - | - |
| Distribution Maintenance | | | | | | | | | | | |
| | CA | 20,470,244 | - | (5,876,471) | - | - | - | - | - | - | - |
| | ID | 6,834,223 | - | (5,147,455) | - | - | - | - | - | - | - |
| | OR | 78,536,105 | - | (32,569,300) | - | - | - | - | (16,814) | (61,564,703) | - |
| | SNPD | 12,184,335 | - | (9,054,389) | - | - | - | - | (68,441) | - | - |
| | UT | 60,452,695 | - | (36,151,640) | - | - | - | - | - | - | - |
| | WA | 10,788,723 | - | (7,380,325) | - | - | - | - | - | - | - |
| | WYP | 11,165,325 | - | (8,043,575) | - | - | - | - | - | - | - |
| | WYU | 2,075,313 | - | (831,449) | - | - | - | - | - | - | - |
| | **Distribution Maintenance Total** | 202,506,962 | - | (105,054,605) | - | - | - | - | (85,255) | (61,564,703) | - |
| Customer Accounts Operations | | | | | | | | | | | |
| | CA | 1,274,095 | - | (411,221) | - | - | - | - | - | - | - |
| | CN | 41,722,304 | - | (28,327,307) | - | - | - | - | (14,443) | - | - |
| | ID | 1,507,505 | - | (730,796) | - | - | - | - | - | - | - |
| | OR | 11,180,100 | (9,820) | (1,785,456) | - | - | - | - | (9) | - | - |
| | UT | 13,249,652 | - | (5,165,754) | - | - | - | - | - | - | - |
| | WA | 8,712,775 | - | (946,033) | - | - | - | - | - | - | - |
| | WYP | 2,870,088 | - | (1,002,110) | - | - | - | - | - | - | - |
| | WYU | 275,681 | - | (204,339) | - | - | - | - | - | - | - |
| | **Customer Accounts Operations Total** | 80,792,201 | (9,820) | (38,573,016) | - | - | - | - | (14,451) | - | - |
| Customer Service Operations | | | | | | | | | | | |
| | CA | 48,063 | 53,462 | - | - | - | - | - | - | - | - |
| | CN | 6,805,379 | (507,225) | (4,920,373) | - | - | - | - | (12,520) | - | - |
| | ID | 204,339 | 2,882 | (0) | - | - | - | - | - | - | - |
| | OR | 2,826,705 | 364,974 | (2,216,691) | - | - | - | - | (9,147) | - | - |
| | OTHER | 142,989,906 | - | (1,410) | - | - | - | - | - | - | - |
| | UT | 4,375,880 | 7,006 | (2,881,929) | - | - | - | - | - | - | - |
| | WA | 456,466 | - | (170,516) | - | - | - | - | - | - | - |
| | WYP | 1,273,133 | 1,571 | (978,104) | - | - | - | - | - | - | - |
| | WYU | - | - | - | - | - | - | - | - | - | - |
| | **Customer Service Operations Total** | 158,979,871 | (77,330) | (11,169,021) | - | - | - | - | (21,667) | - | - |
| A&G Operations & Maintenance | | | | | | | | | | | |
| | 920 | 80,456,405 | - | (79,514,314) | - | - | - | - | - | - | - |
| | 921 | 17,550,657 | 1,606,974 | (41,013) | - | - | - | - | (288,107) | - | - |
| | 922 | (48,437,529) | - | 24,724,390 | - | - | - | - | - | - | - |
| | 923 | 52,372,720 | (225,008) | - | - | - | - | - | - | - | - |
| | 924 | 19,551,510 | - | - | - | (1,218) | - | - | - | - | - |
| | 925 | 456,920,112 | - | - | - | (402,546,523) | - | - | (65) | - | - |
| | 926 | 5,622,520 | - | - | - | - | - | - | - | - | - |
| | 928 | 27,288,977 | - | (937,404) | - | - | - | - | - | - | - |
| | 929 | (10,325,949) | (13,300) | 27,685,156 | - | - | - | - | 138 | - | - |
| | 930 | 2,839,086 | - | - | - | - | - | (627,501) | - | - | - |
| | 931 | (3,678,774) | - | - | - | - | - | - | - | - | - |
| | 935 | 30,271,987 | - | (2,267,719) | - | - | - | - | (460) | - | - |
| | **A&G Operations & Maintenance Total** | 630,431,721 | 1,368,666 | (30,350,905) | - | (402,547,741) | - | (627,501) | (288,495) | - | - |
| | **Grand Total** | 3,837,152,773 | 2,228,731 | (490,396,090) | 7,385,140 | (402,547,741) | 4,824,708 | (627,501) | (707,878) | (70,710,260) | (61,392,900) |



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**PacifiCorp**
**Oregon General Rate Case - December 2025**
**O&M Expense Escalation**
**12 Months Ending December 2025**

| Function | Allocation Code | 5.1_R Net Power Costs | 8.9 Remove Rolling Hills | 8.10 Deer Creek Mine Closure | 8.11_R Emissions Control Investment Adjustment | 8.13 Cholla Unit Retirement | 8.20 Klamath Transfer Costs | O&M Before Escalation | Escalation Percentages | 4.10_R O&M Expense Escalation | O&M After Escalation |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Steam Operation | | | | | | | | | | | |
| | NPCID | - | - | - | - | - | - | 87,693 | 0.00% | - | 87,693 |
| | NPCSE | - | - | - | - | - | - | 612,767,769 | 0.00% | - | 612,767,769 |
| | NPCSSECH | - | - | - | - | - | - | - | 0.00% | - | 0 |
| | NPCWYP | - | - | - | - | - | - | 253,319 | 0.00% | - | 253,319 |
| | SE | - | - | - | - | - | - | 22,085,310 | 4.84% | 1,068,402 | 23,153,712 |
| | SG | - | - | (6,538,963) | - | - | - | 53,316,126 | 4.84% | 2,579,229 | 55,895,355 |
| | SNPPS | - | - | - | - | - | - | 5,282,486 | 4.84% | 255,546 | 5,538,032 |
| | SSECH | - | - | - | - | - | - | - | 4.84% | - | 0 |
| | SSGCH | - | - | - | - | - | - | (16,495) | 4.84% | (798) | (17,293) |
| | CA | - | - | - | - | - | - | - | 4.84% | - | 0 |
| | ID | - | - | - | - | - | - | - | 4.84% | - | 0 |
| | OR | - | - | - | - | - | - | - | 4.84% | - | 0 |
| | WA | - | - | - | - | - | - | - | 4.84% | - | 0 |
| | WYP | - | - | - | - | - | - | - | 4.84% | - | 0 |
| | **Steam Operation Total** | - | - | (6,538,963) | - | - | - | 693,776,210 | | 3,902,380 | 697,678,589 |
| Steam Maintenance | | | | | | | | | | | |
| | SG | - | - | - | - | - | - | (30,879,366) | 0.31% | (96,487) | (30,975,853) |
| | SNPPS | - | - | - | - | - | - | 88,568,443 | 0.31% | 276,745 | 88,845,189 |
| | SSGCH | - | - | - | - | - | - | - | 0.31% | - | 0 |
| | **Steam Maintenance Total** | - | - | - | - | - | - | 57,689,077 | | 180,258 | 57,869,335 |
| Hydro Operations | | | | | | | | | | | |
| | SG-P | - | - | - | - | - | - | 16,187,168 | 1.87% | 302,451 | 16,489,619 |
| | SG-U | - | - | - | - | - | - | 1,846,866 | 1.87% | 34,508 | 1,881,374 |
| | SG | - | - | - | - | - | (2,095,842) | (2,104,083) | 1.87% | (39,314) | (2,143,397) |
| | **Hydro Operations Total** | - | - | - | - | - | (2,095,842) | 15,929,951 | | 297,645 | 16,227,596 |
| Hydro Maintenance | | | | | | | | | | | |
| | SG-P | - | - | - | - | - | - | 4,102,884 | -0.29% | (12,040) | 4,090,843 |
| | SG-U | - | - | - | - | - | - | 1,094,315 | -0.29% | (3,211) | 1,091,104 |
| | SG | - | - | - | - | - | - | 0 | -0.29% | (0) | 0 |
| | **Hydro Maintenance Total** | - | - | - | - | - | - | 5,197,199 | | (15,252) | 5,181,948 |
| Purchased Power | | | | | | | | | | | |
| | NPCSE | - | - | - | - | - | - | 20,074,007 | 0.00% | - | 20,074,007 |
| | NPCSG | (77,418,726) | - | - | - | - | - | 1,130,362,458 | 0.00% | - | 1,130,362,458 |
| | NPCCA | - | - | - | - | - | - | 2,514 | 0.00% | - | 2,514 |
| | NPCOR | - | - | - | - | - | - | 80,131 | 0.00% | - | 80,131 |
| | NPCUT | - | - | - | - | - | - | 13,361,355 | 0.00% | - | 13,361,355 |
| | OTHER | - | - | - | - | - | - | (519,795,484) | 0.00% | - | (519,795,484) |
| | **Purchase Power Total** | (77,418,726) | - | - | - | - | - | 644,084,982 | | - | 644,084,982 |
| Other Operations | | | | | | | | | | | |
| | NPCSE | - | - | - | - | - | - | 621,099,417 | 0.00% | - | 621,099,417 |
| | NPCSSECT | - | - | - | - | - | - | 628,119 | 0.00% | - | 628,119 |
| | SG-W | - | - | - | - | - | - | 16,538,766 | 4.37% | 722,587 | 17,261,353 |
| | SNPPO | - | - | - | - | - | - | 17,021,070 | 4.37% | 743,659 | 17,764,730 |
| | SSGCT | - | - | - | - | - | - | 401,255 | 4.37% | 17,531 | 418,786 |
| | SE | - | - | - | - | - | - | 6,158 | 4.37% | 269 | 6,427 |
| | SG | - | (44,874) | - | - | - | - | 6,402,774 | 4.37% | 279,740 | 6,682,514 |
| | ID | - | - | - | - | - | - | 3,541,074 | 4.37% | 154,711 | 3,695,785 |
| | OR | - | - | - | - | - | - | 8,172,454 | 4.37% | 357,059 | 8,529,512 |
| | UT | - | - | - | - | - | - | 35,000 | 4.37% | 1,529 | 36,529 |
| | WYU | - | - | - | - | - | - | 61,932 | 4.37% | 2,706 | 64,638 |
| | **Other Operations Total** | - | (44,874) | - | - | - | - | 673,908,019 | | 2,279,791 | 676,187,810 |
| Other Maintenance | | | | | | | | | | | |
| | SNPPO | - | - | - | - | - | - | 5,619,531 | 2.38% | 133,994 | 5,753,525 |
| | SSGCT | - | - | - | - | - | - | 377,199 | 2.38% | 8,994 | 386,193 |
| | SG | - | (1,112,621) | - | - | - | - | 1,718,014 | 2.38% | 40,965 | 1,758,979 |
| | SG-W | - | - | - | - | - | - | 19,716,320 | 2.38% | 470,124 | 20,186,444 |
| | **Other Maintenance Total** | - | (1,112,621) | - | - | - | - | 27,431,064 | | 654,078 | 28,085,142 |
| Transmission Operations | | | | | | | | | | | |
| | NPCSE | - | - | - | - | - | - | 25,912,615 | 0.00% | - | 25,912,615 |
| | NPCSG | - | - | - | - | - | - | 141,048,505 | 0.00% | - | 141,048,505 |
| | SG | - | - | - | - | - | - | (16,087) | 0.07% | (11) | (16,098) |
| | SNPT | - | - | - | - | - | - | 16,166,593 | 0.07% | 11,099 | 16,177,692 |
| | **Transmission Operations Total** | - | - | - | - | - | - | 183,111,625 | | 11,088 | 183,122,714 |
| Transmission Maintenance | | | | | | | | | | | |
| | SNPT | - | - | - | - | - | - | 21,187,914 | -3.27% | (693,845) | 20,494,069 |
| | SG | - | - | - | - | - | - | (9,151,001) | -3.27% | 299,670 | (8,851,331) |
| | **Transmission Maintenance Total** | - | - | - | - | - | - | 12,036,913 | | (394,175) | 11,642,737 |



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Oregon General Rate Case - December 2025
O&M Expense Escalation
12 Months Ending December 2025

| Function | Allocation Code | 5.1_R Net Power Costs | 8.9 Remove Rolling Hills | 8.10 Deer Creek Mine Closure | 8.11_R Emissions Control Investment Adjustment | 8.13 Cholla Unit Retirement | 8.20 Klamath Transfer Costs | O&M Before Escalation | Escalation Percentages | 4.10_R O&M Expense Escalation | O&M After Escalation |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Distribution Operations | | | | | | | | | | | |
| | CA | - | - | - | - | - | - | (57,623) | 2.13% | (1,225) | (58,848) |
| | ID | - | - | - | - | - | - | 832,842 | 2.13% | 17,702 | 850,545 |
| | OR | - | - | - | - | - | - | 1,885,525 | 2.13% | 40,078 | 1,925,602 |
| | SNPD | - | - | - | - | - | - | (11,573,464) | 2.13% | (245,999) | (11,819,463) |
| | UT | - | - | - | - | - | - | 7,622,618 | 2.13% | 162,022 | 7,784,640 |
| | WA | - | - | - | - | - | - | 541,226 | 2.13% | 11,504 | 552,729 |
| | WYP | - | - | - | - | - | - | 1,829,954 | 2.13% | 38,896 | 1,868,850 |
| | WYU | - | - | - | - | - | - | 56,927 | 2.13% | 1,210 | 58,137 |
| | **Distribution Operations Total** | - | - | - | - | - | - | 1,138,005 | | 24,189 | 1,162,193 |
| Distribution Maintenance | | | | | | | | | | | |
| | CA | - | - | - | - | - | - | 14,593,773 | -4.41% | (643,917) | 13,949,855 |
| | ID | - | - | - | - | - | - | 1,686,768 | -4.41% | (74,425) | 1,612,343 |
| | OR | - | - | - | - | - | - | (15,614,712) | -4.41% | 688,964 | (14,925,748) |
| | SNPD | - | - | - | - | - | - | 3,061,505 | -4.41% | (135,082) | 2,926,423 |
| | UT | - | - | - | - | - | - | 24,301,055 | -4.41% | (1,072,229) | 23,228,826 |
| | WA | - | - | - | - | - | - | 3,408,398 | -4.41% | (150,388) | 3,258,010 |
| | WYP | - | - | - | - | - | - | 3,121,751 | -4.41% | (137,740) | 2,984,010 |
| | WYU | - | - | - | - | - | - | 1,243,863 | -4.41% | (54,883) | 1,188,981 |
| | **Distribution Maintenance Total** | - | - | - | - | - | - | 35,802,400 | | (1,579,700) | 34,222,700 |
| Customer Accounts Operations | | | | | | | | | | | |
| | CA | - | - | - | - | - | - | 862,874 | 2.53% | 21,803 | 884,677 |
| | CN | - | - | - | - | - | - | 13,380,554 | 2.53% | 338,104 | 13,718,658 |
| | ID | - | - | - | - | - | - | 776,710 | 2.53% | 19,626 | 796,336 |
| | OR | - | - | - | - | - | - | 9,384,815 | 2.53% | 237,138 | 9,621,954 |
| | UT | - | - | - | - | - | - | 8,083,898 | 2.53% | 204,266 | 8,288,164 |
| | WA | - | - | - | - | - | - | 7,766,742 | 2.53% | 196,252 | 7,962,995 |
| | WYP | - | - | - | - | - | - | 1,867,978 | 2.53% | 47,201 | 1,915,179 |
| | WYU | - | - | - | - | - | - | 71,342 | 2.53% | 1,803 | 73,145 |
| | **Customer Accounts Operations Total** | - | - | - | - | - | - | 42,194,913 | | 1,066,194 | 43,261,107 |
| Customer Service Operations | | | | | | | | | | | |
| | CA | - | - | - | - | - | - | 101,525 | -0.87% | (880) | 100,644 |
| | CN | - | - | - | - | - | - | 1,365,261 | -0.87% | (11,838) | 1,353,422 |
| | ID | - | - | - | - | - | - | 207,221 | -0.87% | (1,797) | 205,424 |
| | OR | - | - | - | - | - | - | 965,842 | -0.87% | (8,375) | 957,467 |
| | OTHER | - | - | - | - | - | - | 142,988,495 | -0.87% | (1,239,877) | 141,748,619 |
| | UT | - | - | - | - | - | - | 1,500,957 | -0.87% | (13,015) | 1,487,942 |
| | WA | - | - | - | - | - | - | 285,951 | -0.87% | (2,480) | 283,471 |
| | WYP | - | - | - | - | - | - | 296,601 | -0.87% | (2,572) | 294,029 |
| | WYU | - | - | - | - | - | - | - | -0.87% | - | 0 |
| | **Customer Service Operations Total** | - | - | - | - | - | - | 147,711,852 | | (1,280,834) | 146,431,018 |
| A&G Operations & Maintenance | | | | | | | | | | | |
| | 920 | - | - | - | - | 702,610 | - | 1,644,701 | 5.52% | 90,816 | 1,735,517 |
| | 921 | - | - | - | - | - | - | 18,828,511 | 1.46% | 274,776 | 19,103,287 |
| | 922 | - | - | - | - | - | - | (23,713,140) | 5.52% | (1,309,375) | (25,022,515) |
| | 923 | - | - | - | - | - | - | 52,147,713 | 5.88% | 3,063,931 | 55,211,643 |
| | 924 | - | - | - | - | - | - | 19,550,292 | 0.00% | - | 19,550,292 |
| | 925 | - | - | - | - | - | - | 54,373,523 | 0.00% | - | 54,373,523 |
| | 926 | - | - | 2,967,013 | - | - | - | 8,589,534 | 0.00% | - | 8,589,534 |
| | 928 | - | - | - | - | - | - | 26,351,573 | 1.97% | 517,942 | 26,869,515 |
| | 929 | - | (280,729) | - | - | - | - | 17,065,316 | 5.52% | 942,300 | 18,007,616 |
| | 930 | - | - | - | (1,196,832) | - | - | 1,014,753 | -5.85% | (59,358) | 955,394 |
| | 931 | - | - | - | - | 29,534 | - | (3,649,240) | 6.73% | (245,542) | (3,894,782) |
| | 935 | - | - | - | - | - | - | 28,003,807 | -0.07% | (19,115) | 27,984,692 |
| | **A&G Operations & Maintenance Total** | - | (280,729) | 2,967,013 | (1,196,832) | 732,144 | - | 200,207,342 | | 3,256,374 | 203,463,717 |
| | **Grand Total** | (77,418,726) | (1,438,225) | (3,571,949) | (1,196,832) | 732,144 | (2,095,842) | 2,740,219,551 | | 8,402,036 | 2,748,821,587 |
| | | | | | | | | | | **Ref 4.10.3_R** | |



Exhibit PAC/3302
Cheung/76

**PacifiCorp** PAGE 4.12_R
**Oregon General Rate Case - December 2025**
**Customer Payment Fees**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Expense:** | | | | | | | |
| *Customer Account Expense* | *903* | *3* | *1,570,606* | *OR* | *Situs* | *1,570,606* | *4.12.1_R* |

**Description of Adjustment:**

This adjustment adds into test period results the pro forma incremental expense due to the proposed elimination of payment fees beginning with the effective date of this general rate case. For details, please refer to the direct testimony of company witness Robert M. Meredith.

*This adjustment has been updated to reflect the Company's reply position as supported by Company witness Robert M. Meredith.*

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Customer Payment Fees**
**Summary of Fees by Type**

| | Fee Count | | | | | | |
|---|---|---|---|---|---|---|---|
| **Customer Accounts Expense** | **2021** | **2022** | **2023** | **3-Yr. Avg.** | **Current Fee** | **Total Co. ($)** | |
| Pay Station | 79,193 | 76,386 | 77,021 | 77,533 | $ 1.65 | 127,930 | |
| Residential ACH Payment | 26,863 | 22,388 | 23,989 | 24,413 | $ 1.99 | 48,583 | |
| Residential Card Payment | 532,960 | 602,167 | 692,444 | 609,190 | $ 1.99 | 1,212,289 | |
| Non-Residential ACH Payment | 1,459 | 1,703 | 1,620 | 1,594 | $ 7.99 | 12,736 | |
| Non-Residential Card Payment | 16,807 | 22,109 | 24,564 | 21,160 | $ 7.99 | 169,068 | |
| | | | | | | **1,570,606** | **Ref. 4.12_R** |

# Tab 5 - Net Power Cost

**PacifiCorp** 

**Oregon General Rate Case – December 2025**

**Net Power Cost Adjustment Index**

The following adjustments were used to develop pro forma net power costs for the test period. The Company's booked power costs for the 12 months ended June 2023 provide the starting point for establishing the adjustment amounts for the December 2025 test period.

5.1_R NPC Adjustment
5.2_R WRAP Fees & COSR Materials

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Tab 5 Adjustment Summary**

| | | Total Adjustments | 5.1_R NPC Adjustment | 5.2_R WRAP Fees & COSR Materials |
|---|---|---|---|---|
| 1 | Operating Revenues: | | | |
| 2 | General Business Revenues | - | - | - |
| 3 | Interdepartmental | - | - | - |
| 4 | Special Sales | 17,826,285 | 17,826,285 | - |
| 5 | Other Operating Revenues | - | - | - |
| 6 | Total Operating Revenues | 17,826,285 | 17,826,285 | - |
| 7 | | | | |
| 8 | Operating Expenses: | | | |
| 9 | Steam Production | 26,827,464 | 26,827,464 | - |
| 10 | Nuclear Production | - | - | - |
| 11 | Hydro Production | - | - | - |
| 12 | Other Power Supply | 23,376,731 | 23,289,807 | 86,924 |
| 13 | Transmission | 6,766,182 | 6,766,182 | - |
| 14 | Distribution | - | - | - |
| 15 | Customer Accounting | - | - | - |
| 16 | Customer Service & Info | - | - | - |
| 17 | Sales | - | - | - |
| 18 | Administrative & General | - | - | - |
| 19 | | | | |
| 20 | Total O&M Expenses | 56,970,377 | 56,883,454 | 86,924 |
| 21 | | | - | - |
| 22 | Depreciation | - | - | - |
| 23 | Amortization | - | - | - |
| 24 | Taxes Other Than Income | - | - | - |
| 25 | Income Taxes - Federal | (7,854,659) | (7,837,223) | (17,436) |
| 26 | Income Taxes - State | (1,778,863) | (1,774,914) | (3,949) |
| 27 | Income Taxes - Def Net | - | - | - |
| 28 | Investment Tax Credit Adj. | - | - | - |
| 29 | Misc Revenue & Expense | - | - | - |
| 30 | | | | |
| 31 | Total Operating Expenses: | 47,336,855 | 47,271,316 | 65,539 |
| 32 | | | | |
| 33 | Operating Rev For Return: | (29,510,570) | (29,445,031) | (65,539) |
| 34 | | | | |
| 35 | Rate Base: | | | |
| 36 | Electric Plant In Service | - | - | - |
| 37 | Plant Held for Future Use | - | - | - |
| 38 | Misc Deferred Debits | - | - | - |
| 39 | Elec Plant Acq Adj | - | - | - |
| 40 | Nuclear Fuel | - | - | - |
| 41 | Prepayments | - | - | - |
| 42 | Fuel Stock | - | - | - |
| 43 | Material & Supplies | - | - | - |
| 44 | Working Capital | 1,436,254 | 1,434,266 | 1,989 |
| 45 | Weatherization Loans | - | - | - |
| 46 | Misc Rate Base | - | - | - |
| 47 | | | | |
| 48 | Total Electric Plant: | 1,436,254 | 1,434,266 | 1,989 |
| 49 | | | - | - |
| 50 | Rate Base Deductions: | | - | - |
| 51 | Accum Prov For Deprec | - | - | - |
| 52 | Accum Prov For Amort | - | - | - |
| 53 | Accum Def Income Tax | - | - | - |
| 54 | Unamortized ITC | - | - | - |
| 55 | Customer Adv For Const | - | - | - |
| 56 | Customer Service Deposits | - | - | - |
| 57 | Misc Rate Base Deductions | - | - | - |
| 58 | | | | |
| 59 | Total Rate Base Deductions | - | - | - |
| 60 | | | | |
| 61 | Total Rate Base: | 1,436,254 | 1,434,266 | 1,989 |
| 62 | | | | |
| 63 | Return on Rate Base | -0.602% | -0.600% | -0.001% |
| 64 | | | | |
| 65 | Return on Equity | -1.203% | -1.200% | -0.003% |
| 66 | | | | |
| 67 | TAX CALCULATION: | | | |
| 68 | Operating Revenue | (39,144,093) | (39,057,169) | (86,924) |
| 69 | Other Deductions | - | - | - |
| 70 | Interest (AFUDC) | - | - | - |
| 71 | Interest | 37,910 | 37,857 | 52 |
| 72 | Schedule "M" Additions | - | - | - |
| 73 | Schedule "M" Deductions | - | - | - |
| 74 | Income Before Tax | (39,182,002) | (39,095,026) | (86,976) |
| 75 | | | | |
| 76 | State Income Taxes | (1,778,863) | (1,774,914) | (3,949) |
| 77 | Taxable Income | (37,403,139) | (37,320,112) | (83,027) |
| 78 | | | | |
| 79 | Federal Income Taxes + Other | (7,854,659) | (7,837,223) | (17,436) |
| | APPROXIMATE PRICE CHANGE | 40,684,319 | 40,594,088 | 90,231 |

**PacifiCorp** PAGE 5.1_R
**Oregon General Rate Case - December 2025**
**NPC Adjustment**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Revenue:** | | | | | | | |
| **Sales for Resale (Account 447)** | | | | | | | |
| Existing Firm PPL | 447NPC | 3 | - | SG | 26.884% | - | 5.1.1_R |
| Existing Firm UPL | 447NPC | 3 | - | SG | 26.884% | - | 5.1.1_R |
| *Post-Merger Firm* | *447NPC* | *3* | *66,307,769* | *SG* | *26.884%* | *17,826,285* | *5.1.1_R* |
| Non-Firm | 447NPC | 3 | - | SE | 26.339% | - | 5.1.1_R |
| **Total Sales for Resale** | | | 66,307,769 | | | 17,826,285 | |
| **Adjustment to Expense:** | | | | | | | |
| **Purchased Power (Account 555)** | | | | | | | |
| *Existing Firm Demand PPL* | *555NPC* | *3* | *34,203,036* | *SG* | *26.884%* | *9,195,198* | *5.1.1_R* |
| *Existing Firm Demand UPL* | *555NPC* | *3* | *254,581* | *SG* | *26.884%* | *68,442* | *5.1.1_R* |
| *Existing Firm Energy* | *555NPC* | *3* | *79,995,471* | *SE* | *26.339%* | *21,070,102* | *5.1.1_R* |
| *Post-merger Firm* | *555NPC* | *3* | *175,442,961* | *SG* | *26.884%* | *47,166,361* | *5.1.1_R* |
| Post-merger Firm - Situs | 555NPC | 3 | (13,361,355) | UT | Situs | - | 5.1.1_R |
| Post-merger Firm - Situs | 555NPC | 3 | (80,131) | OR | Situs | (80,131) | 5.1.1_R |
| Post-merger Firm - Situs | 555NPC | 3 | (2,514) | CA | Situs | - | 5.1.1_R |
| Secondary Purchases | 555NPC | 3 | (20,074,007) | SE | 26.339% | (5,287,317) | 5.1.1_R |
| **Total Purchased Power Adjustments:** | | | 256,378,042 | | | 72,132,656 | |
| **Wheeling Expense (Account 565)** | | | | | | | |
| *Existing Firm PPL* | *565NPC* | *3* | *39,979,703* | *SG* | *26.884%* | *10,748,206* | *5.1.1_R* |
| Existing Firm UPL | 565NPC | 3 | - | SG | 26.884% | - | 5.1.1_R |
| *Post-merger Firm* | *565NPC* | *3* | *(2,018,514)* | *SG* | *26.884%* | *(542,661)* | *5.1.1_R* |
| *Non-Firm* | *565NPC* | *3* | *(13,058,004)* | *SE* | *26.339%* | *(3,439,363)* | *5.1.1_R* |
| **Total Wheeling Expense Adjustments:** | | | 24,903,185 | | | 6,766,182 | |
| **Fuel Expense (Accounts 501, 503, 547)** | | | | | | | |
| Fuel - Overburden Amortization - Idaho | 501NPC | 3 | (87,693) | ID | Situs | - | 5.1.1_R |
| Fuel - Overburden Amortization - Wyoming | 501NPC | 3 | (253,319) | WYP | Situs | - | 5.1.1_R |
| *Fuel Consumed - Coal* | *501NPC* | *3* | *142,824,240* | *SE* | *26.339%* | *37,618,646* | *5.1.1_R* |
| *Fuel Consumed - Gas* | *501NPC* | *3* | *(35,174,692)* | *SE* | *26.339%* | *(9,264,704)* | *5.1.1_R* |
| *Steam from Other Sources* | *503NPC* | *3* | *(5,795,480)* | *SE* | *26.339%* | *(1,526,478)* | *5.1.1_R* |
| *Natural Gas Consumed* | *547NPC* | *3* | *(70,387,889)* | *SE* | *26.339%* | *(18,539,550)* | *5.1.1_R* |
| *Simple Cycle Combustion Turbines* | *547NPC* | *3* | *17,288,196* | *SE* | *26.339%* | *4,553,558* | *5.1.1_R* |
| Cholla / APS Exchange | 501NPC | 3 | - | SE | 26.339% | - | 5.1.1_R |
| **Total Fuel Expense Adjustments:** | | | 48,413,362 | | | 12,841,473 | |
| **Total Power Cost Adjustment** | | | 263,386,819 | | | 73,914,026 | |
| Post-merger Firm Type 1 | 555NPC | 1 | (77,418,726) | SG | 26.884% | (20,813,372) | 5.1.1_R |
| *Oregon Solar Project* | *555NPC* | *3* | *(1,043,485)* | *OR* | *Situs* | *(1,043,485)* | *5.1.4_R* |
| *TAM Settlement Docket UE 434* | *555NPC* | *3* | *(13,000,000)* | *OR* | *Situs* | *(13,000,000)* | |

**Description of Adjustment:**

This net power cost adjustment normalizes power costs by adjusting sales for resale, purchased power, wheeling and fuel in a manner consistent with the contractual terms of sales and purchase agreements, and normal hydro and temperature conditions for the 12 month period ending December 2025. The Aurora study for this adjustment is based on forecast loads for the test period.

As described in the testimony of Sherona L. Cheung, this adjustment is included in the calculation of overall revenue requirement for computational purposes only; the Company is not requesting recovery of NPC as part of the general rate case.

*This adjustment has been updated to reflect NPC forecast consistent with the TAM settlement in docket no. UE 434.*

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Net Power Cost Adjustment**

| Description | FERC Account | (1) Total Account (B Tabs) | (2) Remove Non-NPC / NPC Mechanism Accruals | (3) Unadjusted NPC (1) + (2) | (4) Type 1 Adjustments | (5) Type 1 Normalized NPC (3) + (4) | (6) Type 3 Pro Forma NPC | (7) Type 3 Adjustment (6) - (5) | Factor |
|---|---|---|---|---|---|---|---|---|---|
| **Sales for Resale (Account 447)** | | | | | | | | | |
| Existing Firm Sales PPL | 447.12 | - | - | - | - | - | - | - | SG |
| Existing Firm Sales UPL | 447.122 | - | - | - | - | - | - | - | SG |
| Post-merger Firm Sales | 447.13, .14, .20, .61, .62 | 262,557,563.32 | - | 262,557,563 | - | 262,557,563 | 328,865,333 | 66,307,769 | SG |
| Non-firm Sales | 447.5 | - | - | - | - | - | - | - | SE |
| Transmission Services | 447.9 | 98,620 | (98,620) | - | - | - | - | - | S |
| On-system Wholesale Sales | 447.1 | 14,218,690 | (14,218,690) | - | - | - | - | - | S |
| **Total Revenue Adjustments** | | 276,874,873 | (14,317,310) | 262,557,563 | - | 262,557,563 | 328,865,333 | 66,307,769 | |
| **Purchased Power (Account 555)** | | | | | | | | | |
| Existing Firm Demand PPL | 555.66 | - | - | - | - | - | 34,203,036 | 34,203,036 | SG |
| Existing Firm Demand UPL | 555.68 | - | - | - | - | - | 254,581 | 254,581 | SG |
| Existing Firm Energy | 555.65, 555.69 | - | - | - | - | - | 79,995,471 | 79,995,471 | SE |
| Post-merger Firm | 555.26, .55, .59, .61, .62, .63, .64, .67, .8 | 1,207,781,184 | - | 1,207,781,184 | - | 1,207,781,184 | 1,305,805,419 | 98,024,235 | SG |
| Post-merger Firm - Situs | 555.27 | 13,361,355 | - | 13,361,355 | - | 13,361,355 | - | (13,361,355) | UT |
| Post-merger Firm - Situs | 555.28 | 80,131 | - | 80,131 | - | 80,131 | - | (80,131) | OR |
| Post-merger Firm - Situs | 555.29 | 2,514 | - | 2,514 | - | 2,514 | - | (2,514) | CA |
| Secondary Purchases | 555.7, 555.25 | 20,074,007 | - | 20,074,007 | - | 20,074,007 | - | (20,074,007) | SE |
| NPC Deferral Mechanism | 555.57 | (527,209,781) | 527,209,781 | - | - | - | - | - | OTHER |
| Seasonal Contracts | | - | - | - | - | - | - | - | SG |
| Wind Integration Charge | | - | - | - | - | - | - | - | SG |
| RPS Compliance Purchases | 555.22,555.23,555.24 | 7,414,297 | (7,414,297) | - | - | - | - | - | OTHER |
| BPA Regional Adjustments | 555.11, 555.12, 555.133 | - | - | - | - | - | - | - | S |
| Post-merger Firm Type 1 | | - | - | - | (77,418,726) | (77,418,726) | - | 77,418,726 | SG |
| **Total Purchased Power Adjustment** | | 721,503,708 | 519,795,484 | 1,241,299,192 | (77,418,726) | 1,163,880,466 | 1,420,258,508 | 256,378,042 | |
| **Wheeling (Account 565)** | | | | | | | | | |
| Existing Firm PPL | 565.26 | - | - | - | - | - | 39,979,703 | 39,979,703 | SG |
| Existing Firm UPL | 565.27 | - | - | - | - | - | - | - | SG |
| Post-merger Firm | 565.0, 565.46, 565.1 | 141,048,505 | - | 141,048,505 | - | 141,048,505 | 139,029,991 | (2,018,514) | SG |
| Non-firm | 565.25 | 25,912,615 | - | 25,912,615 | - | 25,912,615 | 12,854,610 | (13,058,004) | SE |
| **Total Wheeling Expense Adjustment** | | 166,961,120 | - | 166,961,120 | - | 166,961,120 | 191,864,304 | 24,903,185 | |
| **Fuel Expense (Accounts 501, 503 and 547)** | | | | | | | | | |
| Fuel - Overburden Amortization - Idaho | 501.12 | 87,693 | - | 87,693 | - | 87,693 | - | (87,693) | ID |
| Fuel - Overburden Amortization - Wyoming | 501.12 | 253,319 | - | 253,319 | - | 253,319 | - | (253,319) | WY |
| Fuel Consumed - Coal | 501.1 | 538,681,522 | - | 538,681,522 | - | 538,681,522 | 681,505,762 | 142,824,240 | SE |
| Fuel Consumed - Gas | 501.35 | 62,875,521 | - | 62,875,521 | - | 62,875,521 | 27,700,829 | (35,174,692) | SE |
| Steam From Other Sources | 503 | 11,210,726 | - | 11,210,726 | - | 11,210,726 | 5,415,246 | (5,795,480) | SE |
| Natural Gas Consumed | 547.1 | 621,099,417 | - | 621,099,417 | - | 621,099,417 | 550,711,527 | (70,387,889) | SE |
| Simple Cycle Combustion Turbines | 547.1 | 628,119 | - | 628,119 | - | 628,119 | 17,916,315 | 17,288,196 | SE |
| Cholla/APS Exchange | 501.1 | 0 | - | - | - | - | - | - | SE |
| Fuel Regulatory Costs Deferral and Amort | 501.15 | 0 | - | - | - | - | - | - | S |
| Fuel Regulatory Costs Deferral and Amort | 501.15 | 482,927 | (482,927) | - | - | - | - | - | SE |
| Miscellaneous Fuel Costs | 501.0, .2, .3, .4, .45, .5, .51 | 21,718,151 | (21,718,151) | - | - | - | - | - | SE |
| Miscellaneous Fuel Costs - Cholla | 501.2,501.45 | 0 | - | - | - | - | - | - | SE |
| **Total Fuel Expense** | | 1,257,037,396 | (22,201,079) | 1,234,836,318 | - | 1,234,836,318 | 1,283,249,679 | 48,413,362 | |
| **Net Power Cost** | | **1,868,627,351** | **511,911,715** | **2,380,539,065** | **(77,418,726)** | **2,303,120,340** | **2,566,507,159** | **263,386,819** | |
| | | | | | **Ref 5.1_R** | | **Ref 5.1.3_R** | **Ref 5.1_R** | |

Exhibit PAC/3302
Cheung/83

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Net Power Cost Study**

**Study Results**
MERGED PEAK/ENERGY SPLIT
**($)**

| | Merged 1/2025 - 12/2025 | Pre-Merger Demand | Pre-Merger Energy | Non-Firm | Post-Merger |
|---|---|---|---|---|---|
| SPECIAL SALES FOR RESALE | | | | | |
| Pacific Pre Merger | - | - | | | |
| Post Merger | 328,865,333 | | | | 328,865,333 |
| Utah Pre Merger | - | - | | | |
| NonFirm Sub Total | - | | | - | |
| TOTAL SPECIAL SALES | 328,865,333 | - | - | - | 328,865,333 |
| PURCHASED POWER & NET INTERCHANGE | | | | | |
| BPA Peak Purchase | - | - | | | |
| Pacific Capacity | - | - | - | | |
| Mid Columbia | 113,879,307 | 34,163,792 | 79,715,515 | | |
| Misc/Pacific | 164,065 | 34,021 | 130,044 | | |
| Q.F. Contracts/PPL | 139,811,513 | 5,223 | 25,448 | | 139,780,842 |
| Small Purchases west | - | | - | | |
| Pacific Sub Total | 253,854,885 | 34,203,036 | 79,871,007 | - | 139,780,842 |
| Gemstate | - | | - | | |
| GSLM | - | | - | | |
| QF Contracts/UPL | 188,498,576 | 254,581 | 109,106 | | 188,134,888 |
| IPP Layoff | - | - | - | | |
| Small Purchases east | 15,358 | | 15,358 | | |
| UP&L to PP&L | - | - | - | | |
| Utah Sub Total | 188,513,934 | 254,581 | 124,464 | - | 188,134,888 |
| Appaloosa 1A Solar | 10,292,182 | | - | | 10,292,182 |
| Appaloosa 1B Solar | 6,861,455 | | - | | 6,861,455 |
| Castle Solar UoU | - | | - | | - |
| Castle Solar IHC | - | | - | | - |
| Cedar Springs Wind | 11,723,272 | | - | | 11,723,272 |
| Cedar Springs Wind III | 8,908,094 | | - | | 8,908,094 |
| Cedar Springs Wind IV | 35,181,067 | | - | | 35,181,067 |
| Combine Hills Wind | - | | - | | - |
| Cove Mountain Solar | 3,802,638 | | - | | 3,802,638 |
| Cove Mountain Solar II | 9,387,257 | | - | | 9,387,257 |
| Deseret Purchase | - | | - | | - |
| Eagle Mountain - UAMPS/UMPA | - | | - | | - |
| Elektron Solar 20yr | - | | - | | - |
| Elektron Solar 25yr | - | | - | | - |
| Graphite Solar | 6,197,453 | | - | | 6,197,453 |
| Hermiston Purchase | - | | - | | - |
| Horseshoe Solar | 6,072,682 | | - | | 6,072,682 |
| Hunter Solar | 6,980,641 | | - | | 6,980,641 |
| Hurricane Purchase | - | | - | | - |
| Milford Solar | 6,870,872 | | - | | 6,870,872 |
| Nucor | 7,129,800 | | - | | 7,129,800 |
| Old Mill Solar | - | | - | | - |
| Monsanto Reserves | 20,600,000 | | - | | 20,600,000 |
| Pavant III Solar | - | | - | | - |
| PGE Cove | 164,065 | | - | | 164,065 |
| Prineville Solar | 1,981,228 | | - | | 1,981,228 |
| Sigurd Solar | 5,858,273 | | - | | 5,858,273 |
| Soda Lake Geothermal | - | | - | | - |
| Three Buttes Wind | 20,575,966 | | - | | 20,575,966 |
| Top of the World Wind | 36,087,543 | | - | | 36,087,543 |
| Wolverine Creek Wind | 10,673,363 | | - | | 10,673,363 |
| Faraday B Solar | 7,312,704 | | - | | 7,312,704 |
| Hornshadow I Solar | 4,742,997 | | - | | 4,742,997 |
| Hornshadow II Solar | 9,485,882 | | - | | 9,485,882 |
| Green River Energy Center | - | | - | | - |
| Anticline Wind | 17,957,893 | | - | | 17,957,893 |
| Boswell Springs Wind | 33,509,492 | | - | | 33,509,492 |
| Two River Wind LLC | - | | - | | - |

| | Merged 1/2025 - 12/2025 | Pre-Merger Demand | Pre-Merger Energy | Non-Firm | Post-Merger |
|---|---|---|---|---|---|
| SPECIAL SALES FOR RESALE | | | | | |
| Pacific Pre Merger | - | - | | | |
| Cedar Creek | 20,759,802 | | - | | 20,759,802 |
| UT Schedule Adjustment | (45,624,390) | | - | | (45,624,390) |
| OR Schedule 126 CSP | 3,363,613 | | - | | 3,363,613 |
| Rush lake_BESS | - | | - | | - |
| Fremont Solar_BESS | - | | - | | - |
| Green River Energy Center_BESS | - | | - | | - |
| Umpqua Storage Placeholder | - | | - | | - |
| Short Term Firm Purchases | 701,586,669 | | - | | 701,586,669 |
| New Firm Sub Total | 977,889,689 | - | - | - | 977,889,689 |
| Non Firm Sub Total | - | | | - | |
| TOTAL PURCHASED PW & NET INT. | 1,420,258,508 | 34,457,618 | 79,995,471 | - | 1,305,805,419 |
| WHEELING & U. OF F. EXPENSE | | | | | |
| Pacific Firm Wheeling and Use of Facilities | 39,979,703 | 39,979,703 | | | |
| Utah Firm Wheeling and Use of Facilities | - | - | | | |
| Post Merger | 139,029,991 | | | | 139,029,991 |
| Nonfirm Wheeling | 12,854,610 | | | 12,854,610 | |
| TOTAL WHEELING & U. OF F. EXPENSE | 191,864,304 | 39,979,703 | - | 12,854,610 | 139,029,991 |
| THERMAL FUEL BURN EXPENSE | | | | | |
| Colstrip | 19,772,839 | | | 19,772,839 | |
| Craig | 20,710,941 | | | 20,710,941 | |
| Dave Johnston | 53,033,647 | | | 53,033,647 | |
| Hayden | 10,191,243 | | | 10,191,243 | |
| Hunter | 238,434,435 | | | 238,434,435 | |
| Huntington | 168,724,040 | | | 168,724,040 | |
| Jim Bridger | 105,208,107 | | | 105,208,107 | |
| Naughton | 43,486,427 | | | 43,486,427 | |
| Wyodak | 21,944,081 | | | 21,944,081 | |
| Chehalis | 97,967,647 | | | 97,967,647 | |
| Currant Creek | 61,973,450 | | | 61,973,450 | |
| Gadsby | 27,700,829 | | | 27,700,829 | |
| Gadsby CT | 17,916,315 | | | 17,916,315 | |
| Hermiston | 34,482,245 | | | 34,482,245 | |
| Jim Bridger - Gas | 88,624,512 | | | 88,624,512 | |
| Lake Side 1 | 97,296,859 | | | 97,296,859 | |
| Lake Side 2 | 93,332,353 | | | 93,332,353 | |
| Naughton - Gas | 18,098,334 | | | 18,098,334 | |
| Gas Physical | (2,703,952) | | | (2,703,952) | |
| Gas Swaps | 14,920,625 | | | 14,920,625 | |
| Clay Basin Gas Storage | (1,690,933) | | | (1,690,933) | |
| Pipeline Reservation Fees | 48,410,388 | | | 48,410,388 | |
| TOTAL FUEL BURN EXPENSE | 1,277,834,434 | - | - | 1,277,834,434 | - |
| OTHER GENERATION EXPENSE | | | | | |
| Blundell | 5,415,246 | | | 5,415,246 | |
| TOTAL OTHER GEN. EXPENSE | 5,415,246 | - | - | 5,415,246 | - |
| TOTAL NET POWER COST BEFORE SETTLEMEN | 2,566,507,159 | 74,437,321 | 79,995,471 | 1,296,104,290 | 1,115,970,077 |
| TAM Settlement Adjustment | (48,355,617) | | | | (48,355,617) |
| NET POWER COST | 2,518,151,542 | | | | |

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**NPC Adjustment**
**Oregon Situs Adjustments**

| | Total | Jan-25 | Feb-25 | Mar-25 | Apr-25 | May-25 | Jun-25 | Jul-25 | Aug-25 | Sep-25 | Oct-25 | Nov-25 | Dec-25 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Net Energy impact - Situs Solar | **(925,207)** | (51,443) | (73,061) | (41,945) | (43,732) | (12,650) | (49,499) | (168,887) | (191,413) | (142,336) | (62,353) | (40,565) | (47,322) |
| REP Adjustments (Total Company) | **(2,279,917)** | (198,550) | (213,762) | (431,198) | (463,087) | (508,293) | (757,822) | 162,330 | 647,486 | 319,777 | (314,368) | (295,655) | (226,773) |
| Allocated on SG Factor (26.884%) | **(612,936)** | (53,378) | (57,468) | (115,924) | (124,497) | (136,650) | (203,734) | 43,641 | 174,071 | 85,969 | (84,515) | (79,484) | (60,966) |
| REP Adjustments (Oregon Allocation) | **494,658** | 63,916 | 87,264 | 299,239 | 337,395 | 382,538 | 528,770 | (354,015) | (753,630) | (435,687) | 153,243 | 153,314 | 32,311 |
| **Total OR Situs Adjustment** | **(1,043,485)** | (40,905) | (43,265) | 141,370 | 169,165 | 233,238 | 275,538 | (479,261) | (770,972) | (492,054) | 6,374 | 33,265 | (75,977) |

Exhibit PAC/3302
Cheung/86

**PacifiCorp** PAGE 5.2_R
**Oregon General Rate Case - December 2025**
**WRAP Fees & COSR Materials**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Expense:** | | | | | | | |
| *WRAP Fee* | *557* | *3* | *263,141* | *SG* | *26.884%* | *70,743* | *5.2.1_R* |
| COSR Materials | 557 | 3 | 60,186 | SG | 26.884% | 16,180 | 5.2.1_R |

**Description of Adjustment:**

The first adjustment reflect into test year base rates results two specific fee items. Given the recent trend in decommissioning coal plants and increasing renewable integration, the Resource Adequacy group is working to coordinate activities related to a comprehensive review of resource adequacy in the Northwest Power Pool (NWPP) region, through the development and implementation of a Western Resource Adequacy Program (WRAP). The second fee is regarding the Committee of State Regulators (COSR) fees which are related to the WRAP Program.

*This adjustment has been updated to reflect corrections identified in the Company's response to OPUC data request 345.*

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**WRAP Fees & COSR Materials**

| Incremental O&M | 12 ME June 2023 | Forecasted Total | Adjustment | |
|---|---|---|---|---|
| Western Resource Adequacy Program (WRAP) | $ 1,029,863 | $ 1,293,004 | $ 263,141 | |
| COSR Materials | $ - | $ 60,186 | $ 60,186 | |
| | **$ 1,029,863** | **$ 1,353,189** | **$ 323,326** | **Ref 5.2_R** |

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**WRAP Fees & COSR Materials**
**Company's response to OPUC Data Request 345**

UE 433 / PacifiCorp
April 30, 2024
OPUC Data Request 345

**OPUC Data Request 345**

**Oregon Corporate Activity Taxes, cash working capital** - Please explain how the Company forecasted its Test Year amount for Western Resource Adequacy Program (WRAP) Fees.

**Response to OPUC Data Request 345**

The Company calculated the forecasted Western Resource Adequacy Program (WRAP) fees according to the confidential forecast table provided by the Western Interstate Energy Board (WEIB). For details of the calculation, please refer to Confidential Attachment OPUC 345.

In the preparation of this response, the Company identified an error in its calculation of the forecasted WRAP fee reflected in this general rate case (GRC). As reflected in Adjustment 5.2, specifically page 5.2.1, in Exhibit PAC/1702, Cheung/133, forecasted WRAP fee reflected in the direct testimony of Company witness, Sherona L. Cheung is $1,052,000 on a total-Company basis, calculated as a simple average of the FY2024-2025 and FY2025-2026 Base Costs. However, upon re-examination, and as reflected on Confidential Attachment OPUC 345, the correct forecast WRAP fee should be $1,293,004, on a total-Company basis. Correcting for this error would result in an increase to Oregon-allocated expense of approximately $65,000.

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.

# Tab 4 - Bcnpcag_rgml $ ? kmprgx_rgml

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Tab 6 Adjustment Summary**

| | | Total Adjustments | 6.1 Depreciation & Amortiation Expense | 6.2 Depreciation & Amortization Reserve | 6.3 Repowering Buy Downs Adjustment | 6.4 Bridger Coal Reclamation Costs_CONF |
|---|---|---|---|---|---|---|
| 1 | Operating Revenues: | | | | | |
| 2 | General Business Revenues | - | - | - | - | - |
| 3 | Interdepartmental | - | - | - | - | - |
| 4 | Special Sales | - | - | - | - | - |
| 5 | Other Operating Revenues | - | - | - | - | - |
| 6 | Total Operating Revenues | - | - | - | - | - |
| 7 | | | | | | |
| 8 | Operating Expenses: | | | | | |
| 9 | Steam Production | 3,818,882 | - | - | - | 3,818,882 |
| 10 | Nuclear Production | - | - | - | - | - |
| 11 | Hydro Production | - | - | - | - | - |
| 12 | Other Power Supply | - | - | - | - | - |
| 13 | Transmission | - | - | - | - | - |
| 14 | Distribution | - | - | - | - | - |
| 15 | Customer Accounting | - | - | - | - | - |
| 16 | Customer Service & Info | - | - | - | - | - |
| 17 | Sales | - | - | - | - | - |
| 18 | Administrative & General | - | - | - | - | - |
| 19 | | | | | | |
| 20 | Total O&M Expenses | 3,818,882 | - | - | - | 3,818,882 |
| 21 | | | | | | |
| 22 | Depreciation | 40,255,866 | 41,091,690 | (835,824) | - | - |
| 23 | Amortization | (2,716,107) | 4,032,446 | - | (6,748,553) | - |
| 24 | Taxes Other Than Income | - | - | - | - | - |
| 25 | Income Taxes - Federal | (3,029,860) | (9,044,074) | 3,714,379 | 2,268,178 | 31,657 |
| 26 | Income Taxes - State | (686,179) | (2,048,232) | 841,204 | 513,680 | 7,170 |
| 27 | Income Taxes - Def Net | (938,932) | - | - | - | (938,932) |
| 28 | Investment Tax Credit Adj. | - | - | - | - | - |
| 29 | Misc Revenue & Expense | - | - | - | - | - |
| 30 | | | | | | |
| 31 | Total Operating Expenses: | 36,703,670 | 34,031,830 | 3,719,759 | (3,966,695) | 2,918,777 |
| 32 | | | | | | |
| 33 | Operating Rev For Return: | (36,703,670) | (34,031,830) | (3,719,759) | 3,966,695 | (2,918,777) |
| 34 | | | | | | |
| 35 | Rate Base: | | | | | |
| 36 | Electric Plant In Service | - | - | - | - | - |
| 37 | Plant Held for Future Use | - | - | - | - | - |
| 38 | Misc Deferred Debits | - | - | - | - | - |
| 39 | Elec Plant Acq Adj | - | - | - | - | - |
| 40 | Nuclear Fuel | - | - | - | - | - |
| 41 | Prepayments | - | - | - | - | - |
| 42 | Fuel Stock | - | - | - | - | - |
| 43 | Material & Supplies | - | - | - | - | - |
| 44 | Working Capital | 3,120 | (336,553) | 138,222 | 84,405 | 117,047 |
| 45 | Weatherization Loans | - | - | - | - | - |
| 46 | Misc Rate Base | - | - | - | - | - |
| 47 | | | | | | |
| 48 | Total Electric Plant: | 3,120 | (336,553) | 138,222 | 84,405 | 117,047 |
| 49 | | - | - | - | - | - |
| 50 | Rate Base Deductions: | - | - | - | - | - |
| 51 | Accum Prov For Deprec | (817,609,078) | - | (644,536,440) | (173,072,637) | - |
| 52 | Accum Prov For Amort | (25,921,413) | - | (25,921,413) | - | - |
| 53 | Accum Def Income Tax | 1,988,755 | - | - | - | 1,988,755 |
| 54 | Unamortized ITC | - | - | - | - | - |
| 55 | Customer Adv For Const | - | - | - | - | - |
| 56 | Customer Service Deposits | - | - | - | - | - |
| 57 | Misc Rate Base Deductions | (8,088,788) | - | - | - | (8,088,788) |
| 58 | | | | | | |
| 59 | Total Rate Base Deductions | (849,630,523) | - | (670,457,853) | (173,072,637) | (6,100,033) |
| 60 | | | | | | |
| 61 | Total Rate Base: | (849,627,403) | (336,553) | (670,319,631) | (172,988,233) | (5,982,986) |
| 62 | | | | | | |
| 63 | Return on Rate Base | 0.655% | -0.691% | 0.980% | 0.426% | -0.060% |
| 64 | | | | | | |
| 65 | Return on Equity | 1.311% | -1.381% | 1.959% | 0.852% | -0.119% |
| 66 | | | | | | |
| 67 | TAX CALCULATION: | | | | | |
| 68 | Operating Revenue | (41,358,641) | (45,124,137) | 835,824 | 6,748,553 | (3,818,882) |
| 69 | Other Deductions | - | - | - | - | - |
| 70 | Interest (AFUDC) | - | - | - | - | - |
| 71 | Interest | (22,425,677) | (8,883) | (17,692,899) | (4,565,976) | (157,919) |
| 72 | Schedule "M" Additions | 3,818,882 | - | - | - | 3,818,882 |
| 73 | Schedule "M" Deductions | - | - | - | - | - |
| 74 | Income Before Tax | (15,114,082) | (45,115,253) | 18,528,723 | 11,314,529 | 157,919 |
| 75 | | | | | | |
| 76 | State Income Taxes | (686,179) | (2,048,232) | 841,204 | 513,680 | 7,170 |
| 77 | Taxable Income | (14,427,902) | (43,067,021) | 17,687,519 | 10,800,849 | 150,750 |
| 78 | | | | | | |
| 79 | Federal Income Taxes + Other | (3,029,860) | (9,044,074) | 3,714,379 | 2,268,178 | 31,657 |
| | APPROXIMATE PRICE CHANGE | (36,706,897) | 46,713,131 | (63,628,030) | (23,187,839) | 3,395,840 |

# Tab 7 - Taxes

**Oregon General Rate Case – December 2025**
**Tax Adjustment Index**

The following adjustments were used to arrive at the normalized levels of tax expenses. The Company's 12 months ended June 2023 accrued tax data provided the basis for known and measurable adjustments to the test period.

7.1_R Interest True-Up
7.2 Property Tax Expense
7.3_R Production Tax Credit
7.4_R PowerTax ADIT Balance
7.5 Pro Forma Tax Balances
7.6_R Wyoming Wind Generation Tax
7.7 TCJA EDIT Adjustment
7.8 Oregon Corporate Activity Tax & Metro BIT
7.9 AFUDC Equity

The tax impacts of the following adjustments are included within the adjustment itself:

- Insurance Expense, 4.5
- Bridger Coal Reclamation Costs, page 6.4
- Trapper Mine Rate Base, page 8.2
- Jim Bridger Mine Rate Base, page 8.3
- Regulatory Assets & Liabilities Amortization, page 8.6_R
- Pension and Other Post-retirement Plan Balances Removal, page 8.8
- Remove Rolling Hills, page 8.9
- Deer Creek Mine Adjustment, page 8.10
- Emissions Control Investment Adjustment, page 8.11_R
- Transmission Project Adjustment, page 8.12
- Cholla Unit 4 Retirement, page 8.13
- Carbon Plant Closure, page 8.15
- Removal of Wildfire Mitigation Capital Rate Base, page 8.16.1
- Wildfire Restoration Costs Deferral Amortization, page 8.18_R
- Aeolus Substation Settlement, page 8.19
- Klamath Regulatory Asset, page 8.20
- Capitalization of Officer Incentives, page R_1
- Remove Customer Service Project, page R_2

The tax impacts of the following adjustment are largely included within adjustment 7.4_R and 7.5, though some impacts are included in the adjustment listed below:

- Pro Forma Plant Additions 8.4
- Confidential New Wind Generation Capital Additions 8.17

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Tab 7 Adjustment Summary**

| | | 7.2 | 7.3_R | 7.4_R | 7.5 | 7.6_R | 7.7 |
|---|---|---|---|---|---|---|---|
| | Total Adjustments | Property Tax Expense | Production Tax Credit | PowerTax ADIT Balance | Pro Forma Tax Balances | Wyoming Wind Generation Tax | TCJA EDIT Adjustment |
| 1 Operating Revenues: | | | | | | | |
| 2 General Business Revenues | - | - | - | - | - | - | - |
| 3 Interdepartmental | - | - | - | - | - | - | - |
| 4 Special Sales | - | - | - | - | - | - | - |
| 5 Other Operating Revenues | - | - | - | - | - | - | - |
| 6 Total Operating Revenues | - | - | - | - | - | - | - |
| 7 | | | | | | | |
| 8 Operating Expenses: | | | | | | | |
| 9 Steam Production | - | - | - | - | - | - | - |
| 10 Nuclear Production | - | - | - | - | - | - | - |
| 11 Hydro Production | - | - | - | - | - | - | - |
| 12 Other Power Supply | - | - | - | - | - | - | - |
| 13 Transmission | - | - | - | - | - | - | - |
| 14 Distribution | - | - | - | - | - | - | - |
| 15 Customer Accounting | - | - | - | - | - | - | - |
| 16 Customer Service & Info | - | - | - | - | - | - | - |
| 17 Sales | - | - | - | - | - | - | - |
| 18 Administrative & General | - | - | - | - | - | - | - |
| 19 | | | | | | | |
| 20 Total O&M Expenses | - | - | - | - | - | - | - |
| 21 | | | | | | | |
| 22 Depreciation | - | - | - | - | - | - | - |
| 23 Amortization | - | - | - | - | - | - | - |
| 24 Taxes Other Than Income | 19,273,245 | 12,584,453 | - | - | - | 533,791 | - |
| 25 Income Taxes - Federal | (29,056,360) | (2,524,278) | (12,923,715) | (5,271,086) | (15,180,680) | (107,072) | (119,084) |
| 26 Income Taxes - State | (6,549,130) | (571,679) | 470 | (1,193,755) | (3,437,604) | (24,249) | (26,969) |
| 27 Income Taxes - Def Net | 18,420,095 | - | - | (1,207,537) | 18,778,459 | - | 849,173 |
| 28 Investment Tax Credit Adj. | - | - | - | - | - | - | - |
| 29 Misc Revenue & Expense | - | - | - | - | - | - | - |
| 30 | | | | | | | |
| 31 Total Operating Expenses: | 2,087,850 | 9,488,496 | (12,923,246) | (7,672,379) | 160,176 | 402,471 | 703,120 |
| 32 | | | | | | | |
| 33 Operating Rev For Return: | (2,087,850) | (9,488,496) | 12,923,246 | 7,672,379 | (160,176) | (402,471) | (703,120) |
| 34 | | | | | | | |
| 35 Rate Base: | | | | | | | |
| 36 Electric Plant In Service | - | - | - | - | - | - | - |
| 37 Plant Held for Future Use | - | - | - | - | - | - | - |
| 38 Misc Deferred Debits | - | - | - | - | - | - | - |
| 39 Elec Plant Acq Adj | - | - | - | - | - | - | - |
| 40 Nuclear Fuel | - | - | - | - | - | - | - |
| 41 Prepayments | - | - | - | - | - | - | - |
| 42 Fuel Stock | - | - | - | - | - | - | - |
| 43 Material & Supplies | - | - | - | - | - | - | - |
| 44 Working Capital | (495,539) | 287,892 | (392,106) | (196,151) | (564,900) | 12,211 | (4,431) |
| 45 Weatherization Loans | - | - | - | - | - | - | - |
| 46 Misc Rate Base | - | - | - | - | - | - | - |
| 47 | | | | | | | |
| 48 Total Electric Plant: | (495,539) | 287,892 | (392,106) | (196,151) | (564,900) | 12,211 | (4,431) |
| 49 | | | | | | | |
| 50 Rate Base Deductions: | | | | | | | |
| 51 Accum Prov For Deprec | - | - | - | - | - | - | - |
| 52 Accum Prov For Amort | - | - | - | - | - | - | - |
| 53 Accum Def Income Tax | (34,395,710) | - | - | (24,770,649) | (2,425,074) | - | (7,199,987) |
| 54 Unamortized ITC | 4,716 | - | - | - | 4,716 | - | - |
| 55 Customer Adv For Const | - | - | - | - | - | - | - |
| 56 Customer Service Deposits | - | - | - | - | - | - | - |
| 57 Misc Rate Base Deductions | 29,710,341 | - | - | - | - | - | 29,710,341 |
| 58 | | | | | | | |
| 59 Total Rate Base Deductions | (4,680,653) | - | - | (24,770,649) | (2,420,358) | - | 22,510,354 |
| 60 | | | | | | | |
| 61 Total Rate Base: | (5,176,192) | 287,892 | (392,106) | (24,966,800) | (2,985,258) | 12,211 | 22,505,923 |
| 62 | | | | | | | |
| 63 Return on Rate Base | -0.041% | -0.233% | 0.318% | 0.240% | 0.002% | -0.010% | -0.064% |
| 64 | | | | | | | |
| 65 Return on Equity | -0.082% | -0.467% | 0.636% | 0.480% | 0.005% | -0.020% | -0.128% |
| 66 | | | | | | | |
| 67 TAX CALCULATION: | | | | | | | |
| 68 Operating Revenue | (19,273,245) | (12,584,453) | - | - | - | (533,791) | - |
| 69 Other Deductions | - | - | - | - | - | - | - |
| 70 Interest (AFUDC) | (38,533,764) | - | - | - | - | - | - |
| 71 Interest | (136,624) | 7,599 | (10,350) | (658,992) | (78,795) | 322 | 594,038 |
| 72 Schedule "M" Additions | 40,628,028 | - | - | 36,353,545 | 4,274,483 | - | - |
| 73 Schedule "M" Deductions | 143,378,120 | - | - | 63,306,702 | 80,071,417 | - | - |
| 74 Income Before Tax | (83,352,948) | (12,592,052) | 10,350 | (26,294,166) | (75,718,140) | (534,113) | (594,038) |
| 75 | | | | | | | |
| 76 State Income Taxes | (6,549,130) | (571,679) | 470 | (1,193,755) | (3,437,604) | (24,249) | (26,969) |
| 77 Taxable Income | (76,803,818) | (12,020,373) | 9,880 | (25,100,410) | (72,280,536) | (509,865) | (567,068) |
| 78 | | | | | | | |
| 79 Federal Income Taxes + Other | (29,056,360) | (2,524,278) | (12,923,715) | (5,271,086) | (15,180,680) | (107,072) | (119,084) |
| APPROXIMATE PRICE CHANGE | 2,337,174 | 13,063,344 | (17,792,156) | (13,099,333) | (86,098) | 554,104 | 3,273,697 |

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Tab 7 Adjustment Summary**

| | | 7.8 Oregon Corporate Activity Tax & Metro BIT | 7.9 AFUDC Equity |
|---|---|---|---|
| 1 | Operating Revenues: | | |
| 2 | General Business Revenues | - | - |
| 3 | Interdepartmental | - | - |
| 4 | Special Sales | - | - |
| 5 | Other Operating Revenues | - | - |
| 6 | Total Operating Revenues | - | - |
| 7 | | | |
| 8 | Operating Expenses: | | |
| 9 | Steam Production | - | - |
| 10 | Nuclear Production | - | - |
| 11 | Hydro Production | - | - |
| 12 | Other Power Supply | - | - |
| 13 | Transmission | - | - |
| 14 | Distribution | - | - |
| 15 | Customer Accounting | - | - |
| 16 | Customer Service & Info | - | - |
| 17 | Sales | - | - |
| 18 | Administrative & General | - | - |
| 19 | | | |
| 20 | Total O&M Expenses | - | - |
| 21 | | | |
| 22 | Depreciation | - | - |
| 23 | Amortization | - | - |
| 24 | Taxes Other Than Income | 6,155,000 | - |
| 25 | Income Taxes - Federal | (653,632) | 7,723,189 |
| 26 | Income Taxes - State | (3,044,432) | 1,749,088 |
| 27 | Income Taxes - Def Net | - | - |
| 28 | Investment Tax Credit Adj. | - | - |
| 29 | Misc Revenue & Expense | - | - |
| 30 | | | |
| 31 | Total Operating Expenses: | 2,456,935 | 9,472,277 |
| 32 | | | |
| 33 | Operating Rev For Return: | (2,456,935) | (9,472,277) |
| 34 | | | |
| 35 | Rate Base: | | |
| 36 | Electric Plant In Service | - | - |
| 37 | Plant Held for Future Use | - | - |
| 38 | Misc Deferred Debits | - | - |
| 39 | Elec Plant Acq Adj | - | - |
| 40 | Nuclear Fuel | - | - |
| 41 | Prepayments | - | - |
| 42 | Fuel Stock | - | - |
| 43 | Material & Supplies | - | - |
| 44 | Working Capital | 74,546 | 287,400 |
| 45 | Weatherization Loans | - | - |
| 46 | Misc Rate Base | - | - |
| 47 | | | |
| 48 | Total Electric Plant: | 74,546 | 287,400 |
| 49 | | | |
| 50 | Rate Base Deductions: | | |
| 51 | Accum Prov For Deprec | - | - |
| 52 | Accum Prov For Amort | - | - |
| 53 | Accum Def Income Tax | - | - |
| 54 | Unamortized ITC | - | - |
| 55 | Customer Adv For Const | - | - |
| 56 | Customer Service Deposits | - | - |
| 57 | Misc Rate Base Deductions | - | - |
| 58 | | | |
| 59 | Total Rate Base Deductions | - | - |
| 60 | | | |
| 61 | Total Rate Base: | 74,546 | 287,400 |
| 62 | | | |
| 63 | Return on Rate Base | -0.061% | -0.233% |
| 64 | | | |
| 65 | Return on Equity | -0.121% | -0.467% |
| 66 | | | |
| 67 | TAX CALCULATION: | | |
| 68 | Operating Revenue | (6,155,000) | - |
| 69 | Other Deductions | - | - |
| 70 | Interest (AFUDC) | - | (38,533,764) |
| 71 | Interest | 1,968 | 7,586 |
| 72 | Schedule "M" Additions | - | - |
| 73 | Schedule "M" Deductions | - | - |
| 74 | Income Before Tax | (6,156,968) | 38,526,178 |
| 75 | | | |
| 76 | State Income Taxes | (3,044,432) | 1,749,088 |
| 77 | Taxable Income | (3,112,535) | 36,777,090 |
| 78 | | | |
| 79 | Federal Income Taxes + Other | (653,632) | 7,723,189 |
| | APPROXIMATE PRICE CHANGE | 3,382,600 | 13,041,015 |

**PacifiCorp** PAGE 7.1_R
**Oregon General Rate Case - December 2025**
**Interest True-Up**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Expense:** | | | | | | | |
| *Interest* | *427* | *3* | *12,255,882* | *OR* | *Situs* | *12,844,562* | *Below* |

| **Adjustment Detail:** | **Total Company** | | |
|---|---|---|---|
| Interest June 2023 - Unadjusted | 457,854,870 | 126,835,298 | 2.15_R |
| Interest December 2025 - Normalized | 519,472,544 | 139,091,179 | Below |
| Adjustment: | 61,617,674 | 12,255,882 | |
| | | | |
| Normalized Rate Base | 20,475,993,217 | 5,269,659,203 | 2.2_R |
| Other & Non-Regulated | (795,066,735) | - | |
| Adjusted Rate Base | 19,680,926,482 | 5,269,659,203 | 2.2_R |
| Weighted Cost of Debt | 2.639% | 2.639% | 2.1_R |
| Normalized Interest | 519,472,544 | 139,091,179 | 2.15_R |

**Description of Adjustment:**

This adjustment synchronizes interest expense with the jurisdictional allocated rate base. This is calculated by multiplying net rate base by the Company's weighted cost of debt. A separate column is not shown for adjustment 7.1 on page 7.0.2 as the interest true-up component is calculated and shown on the adjustment summary pages for each of the adjustments individually.

*This adjustment has been updated to synchronize interest expense with recalculated rate base reflective of corrections and modifications as a result of updating revenue requirement calculations in Reply.*

**PacifiCorp** PAGE 7.3_R
**Oregon General Rate Case - December 2025**
**Production Tax Credit**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Tax:** | | | | | | | |
| FED Renewable Energy Tax Credit | 40910 | 3 | 196,377,610 | SG | 26.884% | 52,794,465 | 7.3.1_R |
| *FED Renewable Energy Tax Credit* | *40910* | *3* | *(244,457,191)* | *SG* | *26.884%* | *(65,720,255)* | *7.3.1_R* |

**Description of Adjustment:**

The Company is entitled to recognize a federal income tax credit as a result of placing renewable generating plants in service. The tax credit is based on the kilowatt-hours generated by a qualified facility during the facility's first ten years of service. This adjustment removes the base period Renewable Energy Tax credits and adds in the pro forma period Renewable Energy Tax credits which are reflected in the Company's Transition Adjustment Mechanism filings annually.

As described in the testimony of Ms. Sherona L. Cheung, this adjustment is included in the calculation of overall revenue requirement for computational purposes only; the Company is not requesting recovery of NPC and PTCs as part of the general rate case. NPC and PTCs are reflected in the Company's Transition Adjustment Mechanism filings annually.

*This adjustment has been updated to synchronize forecasted generation assumptions with the latest TAM settlement forecast in docket no. UE 434.*

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Production Tax Credit**



| Pro Forma Period - December 2025 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Description** | **Total Available KWh** | **In-Service Date** | **Total PTC Eligible KWh** | **Factor (inflated tax per unit)** | **Federal Income Tax Credit** | **Bonus Credit if applicable** | **Federal Income Tax Credit, with Bonus Credit** | |
| **Wind/Geothermal** | | | | | | | | |
| Glenrock **[a]** | 289,681,756 | **9/24/2019** | 266,507,215 | 0.030 | 7,995,216 | | 7,995,216 | |
| Glenrock III **[a]** | 107,574,004 | **11/24/2019** | 88,210,684 | 0.030 | 2,646,321 | | 2,646,321 | |
| Goodnoe | 279,730,322 | **12/20/2019** | 279,730,322 | 0.030 | 8,391,910 | | 8,391,910 | |
| High Plains | 303,591,738 | **12/19/2019** | 303,591,738 | 0.030 | 9,107,752 | | 9,107,752 | |
| Leaning Juniper | 293,902,399 | **9/13/2019** | 293,902,399 | 0.030 | 8,817,072 | | 8,817,072 | |
| Marengo | 476,122,758 | **1/27/2020** | 476,122,758 | 0.030 | 14,283,683 | | 14,283,683 | |
| Marengo II | 228,483,488 | **2/25/2020** | 228,483,488 | 0.030 | 6,854,505 | | 6,854,505 | |
| McFadden Ridge | 93,015,903 | **11/17/2019** | 93,015,903 | 0.030 | 2,790,477 | | 2,790,477 | |
| Rolling Hills **[c]** | - | **10/17/2019** | - | 0.030 | - | | - | |
| Seven Mile | 358,229,363 | **9/9/2019** | 358,229,363 | 0.030 | 10,746,881 | | 10,746,881 | |
| Seven Mile II | 76,379,140 | **9/9/2019** | 76,379,140 | 0.030 | 2,291,374 | | 2,291,374 | |
| Dunlap I | 403,157,990 | **9/7/2020** | 403,157,990 | 0.030 | 12,094,740 | | 12,094,740 | |
| Foote Creek I | 151,868,345 | **3/24/2021** | 151,868,345 | 0.030 | 4,556,050 | | 4,556,050 | |
| Pryor Mountain **[b]** | 812,831,508 | **VARIOUS** | 812,831,508 | 0.030 | 24,384,945 | | 24,384,945 | |
| Cedar Springs II | 632,328,227 | **12/4/2020** | 632,328,227 | 0.030 | 18,969,847 | | 18,969,847 | |
| Ekola Flats **[b]** | 713,529,602 | **VARIOUS** | 713,529,602 | 0.030 | 21,405,888 | | 21,405,888 | |
| TB Flats **[b]** | 1,441,696,410 | **VARIOUS** | 1,441,696,410 | 0.030 | 43,250,892 | | 43,250,892 | |
| Foote Creek II | 6,843,050 | **11/21/2023** | 6,843,050 | 0.030 | 205,292 | 110% | 225,821 | |
| Foote Creek III | 94,530,014 | **11/21/2023** | 94,530,014 | 0.030 | 2,835,900 | 110% | 3,119,490 | |
| Foote Creek IV | 64,027,435 | **11/21/2023** | 64,027,435 | 0.030 | 1,920,823 | 110% | 2,112,905 | |
| Rock Creek I | 600,111,039 | 12/31/2024 | 600,111,039 | 0.030 | 18,003,331 | 110% | 19,803,664 | |
| Rock Creek II | 436,520,883 | 9/30/2025 | 436,520,883 | 0.030 | 13,095,626 | 110% | 14,405,189 | |
| Rock River I | 187,956,644 | 12/1/2024 | 187,956,644 | 0.030 | 5,638,699 | 110% | 6,202,569 | |
| Total KWh Production | 8,052,112,018 | | 8,009,574,157 | | 240,287,224 | | 244,457,191 | |
| Total Federal Production Tax Credit | | | | | | | 244,457,191 | **Ref. 7.3_R** |
| | | | | | | June 2023 Results of Operations PTC | 196,377,610 | **Ref. 7.3_R** |
| | | | | | | Proforma Adjustment | 48,079,581 | |

Repowering In Service dates in **bold** reflect actual in-service dates.

**[a]** Total available Kwh is reflected net of the generation that is not considered PTC eligible because the facility was not fully repowered. For Glenrock and Glenrock III, approximately 8.3% and 17%, respectively of the total generation is not PTC eligible.

**[b]** Pryor Mountain, Ekola Flats, and TB Flats were placed in service using circuits which results in multiple placed in service

**[c]** Oregon does not include Rolling Hills in rate base, therefore, there are no credits for Rolling Hills.

**PacifiCorp** PAGE 7.4_R
**Oregon General Rate Case - December 2025**
**PowerTax ADIT Balance**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Tax:** | | | | | | | |
| ADIT - California | 282 | 3 | (24,068,668) | CA | Situs | - | |
| ADIT - Idaho | 282 | 3 | (31,341,583) | ID | Situs | - | |
| ADIT - Oregon | 282 | 3 | (80,807,614) | OR | Situs | (80,807,614) | |
| ADIT - Other | 282 | 3 | 810,675 | OTHER | 0.000% | - | |
| ADIT - Utah | 282 | 3 | (309,633,021) | UT | Situs | - | |
| ADIT - Washington | 282 | 3 | (26,302,832) | WA | Situs | - | |
| ADIT - Wyoming | 282 | 3 | (67,728,251) | WYP | Situs | - | |
| ADIT - SG | 282 | 3 | (2,542,415,218) | SG | 26.884% | (683,506,900) | |
| ADIT - SO | 282 | 3 | (171,405,033) | SO | 27.425% | (47,008,629) | |
| ADIT - DITBAL | 282 | 1 | 3,020,474,021 | DITBAL | 24.951% | 753,624,533 | |
| ADIT - Accelerated Pollution Control Fac. | 281 | 1 | 128,320,334 | SG | 26.884% | 34,497,840 | |
| | | | (104,097,190) | | | (23,200,770) | 7.4.1_R |
| ADIT - Other Property Flowthrough | 282 | 3 | (1,569,879) | OR | Situs | (1,569,879) | 7.4.1_R |
| Schedule M Adjustment - Permanent | SCHMAP | 3 | (22,041) | SCHMDEXP | 26.812% | (5,910) | 7.4.1_R |
| Schedule M Adjustment | SCHMAT | 3 | 12,781,744 | CIAC | 24.998% | 3,195,232 | 7.4.1_R |
| Schedule M Adjustment | SCHMAT | 3 | 4,758,555 | SCHMDEXP | 26.812% | 1,275,884 | 7.4.1_R |
| Schedule M Adjustment | SCHMAT | 3 | (1,602,441) | SO | 27.425% | (439,477) | 7.4.1_R |
| Schedule M Adjustment | SCHMAT | 3 | 126,219,170 | SNP | 26.136% | 32,988,485 | 7.4.1_R |
| Schedule M Adjustment | SCHMAT | 3 | (2,642,844) | SNPD | 24.998% | (660,669) | 7.4.1_R |
| Schedule M Adjustment | SCHMDT | 3 | (83,720,885) | GPS | 27.425% | (22,960,843) | 7.4.1_R |
| Schedule M Adjustment | SCHMDT | 3 | (12,971,804) | SG | 26.884% | (3,487,360) | 7.4.1_R |
| Schedule M Adjustment | SCHMDT | 3 | (10,828,269) | SO | 27.425% | (2,969,703) | 7.4.1_R |
| Schedule M Adjustment | SCHMDT | 3 | 139,973,599 | TAXDEPR | 26.295% | 36,806,068 | 7.4.1_R |
| Schedule M Adjustment | SCHMDT | 3 | 213,953,199 | SNP | 26.136% | 55,918,541 | 7.4.1_R |
| Deferred Income Tax Expense | 41110 | 3 | (1,169,967) | SCHMDEXP | 26.812% | (313,696) | 7.4.1_R |
| Deferred Income Tax Expense | 41110 | 3 | 393,986 | SO | 27.425% | 108,052 | 7.4.1_R |
| Deferred Income Tax Expense | 41110 | 3 | (3,142,596) | CIAC | 24.998% | (785,599) | 7.4.1_R |
| Deferred Income Tax Expense | 41110 | 3 | (31,033,003) | SNP | 26.136% | (8,110,747) | 7.4.1_R |
| Deferred Income Tax Expense | 41110 | 3 | 649,785 | SNPD | 24.998% | 162,436 | 7.4.1_R |
| Deferred Income Tax Expense | 41010 | 3 | (20,584,119) | GPS | 27.425% | (5,645,291) | 7.4.1_R |
| Deferred Income Tax Expense | 41010 | 3 | (3,189,326) | SG | 26.884% | (857,423) | 7.4.1_R |
| Deferred Income Tax Expense | 41010 | 3 | (2,662,303) | SO | 27.425% | (730,149) | 7.4.1_R |
| Deferred Income Tax Expense | 41010 | 3 | 52,603,817 | SNP | 26.136% | 13,748,468 | 7.4.1_R |
| Deferred Income Tax Expense | 41010 | 3 | 34,414,749 | TAXDEPR | 26.295% | 9,049,361 | 7.4.1_R |
| *Deferred Income Tax Exp. - Flowthrough* | *41110* | *3* | *2,309,545* | *OR* | *Situs* | *2,309,545* | *7.4.1_R* |
| Deferred Income Tax Exp. - Flowthrough | 41110 | 3 | (36,543,359) | SG | 26.884% | (9,824,374) | 7.4.1_R |
| Deferred Income Tax Exp. - Flowthrough | 41110 | 3 | (3,457,437) | SO | 27.425% | (948,218) | 7.4.1_R |
| Def. Inc. Tax Exp. - Other Flowthrough | 41110 | 3 | 630,098 | OR | Situs | 630,098 | 7.4.1_R |

**Description of Adjustment:**

This adjustment reflects the accumulated deferred income tax balances for property on a jurisdictional basis as maintained in the PowerTax System for the 12 months ended December 31, 2024. Updates the property related schedule m-items and associated deferred income tax expense for the 12 months ended December 31, 2024.

*This adjustment was revised to correct the base period Depreciation Flowthrough amount for Oregon.*

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**PowerTax Adjustment for Year Ended December 2024**



| Book Tax Difference | | Total Company | | | STATE Allocation |
|---|---|---|---|---|---|
| Description - ADIT | # | Base Period* | Adjustment | Adjusted Utility | 2020 Protocol |
| Accumulated Deferred Income Taxes (CA) | ** | 0 | (24,068,668) | (24,068,668) | CA |
| Accumulated Deferred Income Taxes (IDU) | ** | 0 | (31,341,583) | (31,341,583) | IDU |
| Accumulated Deferred Income Taxes (OR) | ** | 0 | (80,807,614) | (80,807,614) | OR |
| Accumulated Deferred Income Taxes (OTHER) | ** | 0 | 810,675 | 810,675 | OTHER |
| Accumulated Deferred Income Taxes (UT) | ** | 0 | (309,633,021) | (309,633,021) | UT |
| Accumulated Deferred Income Taxes (WA) | ** | 0 | (26,302,832) | (26,302,832) | WA |
| Accumulated Deferred Income Taxes (WY) | ** | 0 | (67,728,251) | (67,728,251) | WYP |
| Accumulated Deferred Income Taxes (SG) | ** | 0 | (2,542,415,218) | (2,542,415,218) | SG |
| Accumulated Deferred Income Taxes (SO) | ** | 0 | (171,405,033) | (171,405,033) | SO |
| Accumulated Deferred Income Taxes (DITBAL) | ** | (3,020,474,021) | 3,020,474,021 | 0 | DITBAL |
| Accelerated Pollution Control Facilities ADIT (SG) - FERC 281 | ** | (128,320,334) | 128,320,334 | 0 | SG |
| Total | | (3,148,794,355) | **(104,097,190)** | (3,252,891,545) | |
| | | | **Ref. 7.4_R** | **-** | |
| ADIT - Other Property Flowthrough - OR | 105.272 | 13,614,613 | **(1,569,879)** | 12,044,734 | OR |
| | | | **Ref. 7.4_R** | | |

| Book Tax Difference | | Total Company | | | STATE Allocation | |
|---|---|---|---|---|---|---|
| Description - Schedule M Items | # | Base Period* | Adjusted Utility | Adjustment | 2020 Protocol | |
| | | Per Tax Model | Per PowerTax | | | |
| **Schedule M Additions - Permanent:** | | | | | | |
| Book Depreciation Allocated to Capitalized M&E | 105.127 | 153,260 | 131,219 | **(22,041)** | SCHMDEXP | **Ref 7.4_R** |
| **Schedule M Additions - Temporary:** | | | | | | |
| Book Depreciation | 105.120 | 1,086,392,617 | 1,091,151,172 | **4,758,555** | SCHMDEXP | **Ref 7.4_R** |
| Capitalized Labor & Benefits Costs | 105.100 | 4,556,420 | 2,953,979 | **(1,602,441)** | SO | **Ref 7.4_R** |
| CIAC | 105.130 | 137,504,173 | 150,285,917 | **12,781,744** | CIAC | **Ref 7.4_R** |
| Avoided Costs | 105.142 | 90,682,293 | 216,901,463 | **126,219,170** | SNP | **Ref 7.4_R** |
| Reimbursements | 105.140 | 2,642,844 | - | **(2,642,844)** | SNPD | **Ref 7.4_R** |
| Capitalization of Test Energy | 105.146 | - | - | **-** | SG | |
| Total Schedule M Additions | | 1,321,778,347 | 1,461,292,532 | 139,514,185 | | |
| **Schedule M Deductions - Temporary:** | | | | | | |
| Repair Deduction | 105.122 | 173,184,648 | 160,212,844 | **(12,971,804)** | SG | **Ref 7.4_R** |
| Tax Depreciation | 105.125 | 1,264,819,225 | 1,404,792,824 | **139,973,599** | TAXDEPR | **Ref 7.4_R** |
| Book Capitalized Depreciation | 105.137 | 10,828,269 | - | **(10,828,269)** | SO | **Ref 7.4_R** |
| AFUDC - Debt | 105.141 | 47,393,721 | 113,640,559 | **66,246,838** | SNP | **Ref 7.4_R** |
| AFUDC - Equity | 105.141 | 103,254,631 | 250,960,992 | **147,706,361** | SNP | **Ref 7.4_R** |
| Removal Costs | 105.175 | 75,935,704 | 42,596,155 | **(33,339,549)** | GPS | **Ref 7.4_R** |
| Tax Gain / (Loss) on Prop. Disposition | 105.152 | 53,986,355 | 3,605,019 | **(50,381,336)** | GPS | **Ref 7.4_R** |
| Book Gain/Loss on Prop. Disposition | 105.470 | - | - | **-** | GPS | **Ref 7.4_R** |
| Total Schedule M Deductions | | 1,729,402,553 | 1,975,808,393 | 246,405,840 | | |

| Book Tax Difference | | Total Company | | | STATE Allocation | |
|---|---|---|---|---|---|---|
| Description - Deferred Income Tax Expense | # | Base Period* | Adjusted Utility | Adjustment | 2020 Protocol | |
| | | Per Tax Model | Per PowerTax | | | |
| **Flow-through:** | | | | | | |
| California | 105.115 | (506,362) | (1,360,520) | (854,158) | CA | |
| Idaho | 105.115 | (357,584) | (268,534) | 89,050 | IDU | |
| Oregon | 105.115 | (2,358,204) | (48,659) | 2,309,545 | OR | **Ref 7.4_R** |
| Washington | 105.115 | (27,143) | (263,220) | (236,077) | WA | |
| Wyoming - P | 105.115 | (1,344,931) | (197,626) | 1,147,305 | WYP | |
| Wyoming - U | 105.115 | (741,889) | 0 | 741,889 | WYU | |
| OTHER | 105.115 | (18,568) | 0 | 18,568 | NREG | |
| Utah | 105.115 | (397,696) | (2,796,589) | (2,398,893) | UT | |
| FERC | 105.115 | (177,191) | 0 | 177,191 | FERC | |
| SG | 105.115 | (7,590,654) | (44,134,013) | (36,543,359) | SG | **Ref 7.4_R** |
| SO | 105.115 | (650,821) | (4,108,258) | (3,457,437) | SO | **Ref 7.4_R** |
| Total | | (14,171,043) | (53,177,418) | (39,006,375) | | |
| Other Property Flowthrough - Oregon - Tax | 105.272 | (13,852) | (53,286) | (39,434) | | |
| Other Property Flowthrough - Oregon - Book | 105.272 | 272,341 | 941,873 | 669,532 | | |
| Total | | 258,490 | 888,587 | **630,098** | OR | **Ref 7.4_R** |

**PacifiCorp** PAGE 7.6_R
**Oregon General Rate Case - December 2025**
**Wyoming Wind Generation Tax**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Tax:** | | | | | | | |
| *Taxes Other Than Income* | *408* | *3* | *1,985,523* | *SG* | *26.884%* | *533,791* | *7.6.1_R* |

**Description of Adjustment:**

This adjustment normalizes into the test year results the Wyoming Wind Generation Tax that becomes effective January 1, 2012. The Wyoming Wind Generation Tax is an excise tax levied upon the privilege of producing electricity from wind resources in the state of Wyoming. The tax is on the production of any electricity produced from wind resources for sale or trade on or after January 1, 2012, and is to be paid by the person producing the electricity. The tax is one dollar on each megawatt hour of electricity produced from wind resources at the point of interconnection with an electric transmission line.

*This adjustment has been updated to reflect updated generation assumptions consistent with the TAM settlement forecast in docket no. UE 434.*

**PacifiCorp** 
**Oregon General Rate Case - December 2025**
**Wyoming Wind Generation Tax**

| Wind Plant | 2025 NPC MWH Production (b) | Tax Begins | 2025 $1/MWH Tax |
|---|---|---|---|
| Foote Creek | 151,868 | 3/24/2024 | 151,868 |
| Glenrock I | 107,574 | 1/1/2012 | 107,574 |
| Glenrock III | 279,730 | 1/1/2012 | 279,730 |
| Seven Mile Hill | 358,229 | 1/1/2012 | 358,229 |
| Seven Mile Hill II | 76,379 | 1/1/2012 | 76,379 |
| Rolling Hills | - | 1/17/2012 | - |
| High Plains | 303,592 | 9/1/2012 | 303,592 |
| McFadden Ridge | 93,016 | 9/1/2012 | 93,016 |
| Dunlap | 403,158 | 10/1/2013 | 403,158 |
| Cedar Springs Wind II | 632,328 | 12/8/2023 | 632,328 |
| Ekola Flats Wind | 713,530 | VARIOUS | 713,530 |
| TB Flats Wind | 812,832 | VARIOUS | 812,832 |
| Foote Creek II-IV (a) | - | 11/21/2026 | - |
| Rock Creek I (a) | - | 12/31/2027 | - |
| Rock Creek II (a) | - | 9/30/2028 | - |
| Rock River I (a) | - | 12/1/2027 | - |
| Total Wyoming Wind MWH | 3,932,236 | | 3,932,236 |
| June 2023 Results of Operations PTC | | | 1,946,713 |
| Adjustment to normalize to CY December 2025 | | | **1,985,523** **Ref. 7.6_R** |

(a) Electricity produced from a wind turbine shall not be subject to the tax imposed under this chapter until the date three (3) years after the turbine first produced electricity for sale. After such date the production shall be subject to the tax, as provided by W.S. 39-22-103, regardless of whether production first commenced prior to or after January 1, 2012.

(b) WY Wind Generation tax is based on total MWh production, not PTC eligible generation. Glenrock I, Rolling Hills and Glenrock III were not fully repowered, which results in a difference between PTC eligible generation and WY Wind tax eligible generation.

# Tab 6 - P_rc @_qc

**PacifiCorp** 

**Oregon General Rate Case – December 2025**

**Rate Base Adjustment Index**

The Company used year-end rate base as of June 2023 as the starting point for establishing the adjustments made to the test period. Test period electric plant in service is reflected using December 2024 ending balances. Other rate base components are reflected using a December 2025 13 month average balance. The following rate base adjustments are included.

8.1_R Cash Working Capital
8.2 Trapper Mine Rate Base
8.3 Jim Bridger Mine Rate Base
8.4 Pro Forma Plant Additions and Retirements
8.5 Customer Advances for Construction
8.6_R Regulatory Assets & Liabilities Amortization
8.7 Plant Held for Future Use
8.8 Pension and Other Post-retirement Plan Balances Removal
8.9 Remove Rolling Hills
8.10 Deer Creek Mine Adjustment
8.11_R Emissions Control Investment Adjustment
8.12 Transmission Project Adjustment
8.13 Cholla Unit 4 Retirement
8.14_R Miscellaneous Rate Base
8.15 Carbon Plant Closure
8.16 Removal of Wildfire Mitigation Capital Rate Base
8.17 Confidential New Wind Generation Capital Additions
8.18_R Wildfire Restoration Costs Deferral Amortization
8.19 Aeolus Substation Settlement
8.20 Klamath Regulatory Asset

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Tab 8 Adjustment Summary**

| | | 8.2 | 8.3 | 8.4 | 8.5 | 8.6_R | 8.7 |
|---|---|---|---|---|---|---|---|
| | Total Adjustments | Trapper Mine Rate Base | Jim Bridger Mine Rate Base | Pro Forma Plant Additions and Retirements | Customer Advances for Construction | Regulatory Assets & Liabilities Amortization | Plant Held for Future Use |
| 1 Operating Revenues: | | | | | | | |
| 2 General Business Revenues | - | - | - | - | - | - | - |
| 3 Interdepartmental | - | - | - | - | - | - | - |
| 4 Special Sales | - | - | - | - | - | - | - |
| 5 Other Operating Revenues | (4,075,388) | - | - | - | - | (4,075,388) | - |
| 6 Total Operating Revenues | (4,075,388) | - | - | - | - | (4,075,388) | - |
| 7 | | | | | | | |
| 8 Operating Expenses: | | | | | | | |
| 9 Steam Production | (372,219) | - | - | - | - | - | - |
| 10 Nuclear Production | - | - | - | - | - | - | - |
| 11 Hydro Production | (563,449) | - | - | - | - | - | - |
| 12 Other Power Supply | 899,010 | - | - | - | - | - | - |
| 13 Transmission | - | - | - | - | - | - | - |
| 14 Distribution | 829,511 | - | - | - | - | 829,511 | - |
| 15 Customer Accounting | - | - | - | - | - | - | - |
| 16 Customer Service & Info | - | - | - | - | - | - | - |
| 17 Sales | - | - | - | - | - | - | - |
| 18 Administrative & General | 474,830 | - | - | - | - | - | - |
| 19 | | | | | | | |
| 20 Total O&M Expenses | 1,267,683 | - | - | - | - | 829,511 | - |
| 21 | | | | | | | |
| 22 Depreciation | 5,713,429 | - | - | - | - | - | - |
| 23 Amortization | 17,633,929 | - | - | - | - | - | - |
| 24 Taxes Other Than Income | - | - | - | - | - | - | - |
| 25 Income Taxes - Federal | (3,843,113) | (109,959) | (50,297) | (2,859,710) | (144,549) | (816,842) | 39,472 |
| 26 Income Taxes - State | (870,359) | (24,903) | (11,391) | (647,645) | (32,736) | (184,992) | 8,939 |
| 27 Income Taxes - Def Net | (10,331,715) | 124,280 | - | (4,312,521) | - | (203,949) | - |
| 28 Investment Tax Credit Adj. | - | - | - | - | - | - | - |
| 29 Misc Revenue & Expense | - | - | - | - | - | - | - |
| 30 | | | | | | | |
| 31 Total Operating Expenses: | 9,569,854 | (10,581) | (61,688) | (7,819,876) | (177,286) | (376,272) | 48,412 |
| 32 | | | | | | | |
| 33 Operating Rev For Return: | (13,645,242) | 10,581 | 61,688 | 7,819,876 | 177,286 | (3,699,117) | (48,412) |
| 34 | | | | | | | |
| 35 Rate Base: | | | | | | | |
| 36 Electric Plant In Service | 1,280,362,797 | 1,685,813 | 9,499,747 | 1,200,747,833 | - | - | - |
| 37 Plant Held for Future Use | (7,461,409) | - | - | - | - | - | (7,461,409) |
| 38 Misc Deferred Debits | (86,123,100) | - | - | - | - | - | - |
| 39 Elec Plant Acq Adj | (20,258) | - | - | - | - | (20,258) | - |
| 40 Nuclear Fuel | (28,783,408) | - | - | - | - | - | - |
| 41 Prepayments | - | - | - | - | - | - | - |
| 42 Fuel Stock | 7,300,223 | - | - | - | - | - | - |
| 43 Material & Supplies | - | - | - | - | - | - | - |
| 44 Working Capital | (188,679) | (88,222) | (1,872) | (106,417) | (5,379) | (5,228) | 1,469 |
| 45 Weatherization Loans | - | - | - | - | - | - | - |
| 46 Misc Rate Base | - | - | - | - | - | - | - |
| 47 | | | | | | | |
| 48 Total Electric Plant: | 1,165,086,166 | 1,597,590 | 9,497,875 | 1,200,641,416 | (5,379) | (25,486) | (7,459,940) |
| 49 | | | | | | | |
| 50 Rate Base Deductions: | | | | | | | |
| 51 Accum Prov For Deprec | (1,906,517) | - | - | - | - | - | - |
| 52 Accum Prov For Amort | 276,415 | - | - | - | - | - | - |
| 53 Accum Def Income Tax | 41,418,474 | 32,901 | 7,893 | 4,351,639 | - | - | - |
| 54 Unamortized ITC | - | - | - | - | - | - | - |
| 55 Customer Adv For Const | 27,323,942 | - | - | - | 27,323,942 | - | - |
| 56 Customer Service Deposits | - | - | - | - | - | - | - |
| 57 Misc Rate Base Deductions | (807,875) | - | - | - | - | - | - |
| 58 | | | | | | | |
| 59 Total Rate Base Deductions | 66,304,439 | 32,901 | 7,893 | 4,351,639 | 27,323,942 | - | - |
| 60 | | | | | | | |
| 61 Total Rate Base: | 1,231,390,605 | 1,630,492 | 9,505,768 | 1,204,993,055 | 27,318,563 | (25,486) | (7,459,940) |
| 62 | | | | | | | |
| 63 Return on Rate Base | -2.134% | -0.003% | -0.017% | -1.689% | -0.029% | -0.070% | 0.008% |
| 64 | | | | | | | |
| 65 Return on Equity | -4.267% | -0.006% | -0.035% | -3.378% | -0.059% | -0.139% | 0.016% |
| 66 | | | | | | | |
| 67 TAX CALCULATION: | | | | | | | |
| 68 Operating Revenue | (28,690,429) | - | - | - | - | (4,904,899) | - |
| 69 Other Deductions | - | - | - | - | - | - | - |
| 70 Interest (AFUDC) | - | - | - | - | - | - | - |
| 71 Interest | 32,502,210 | 43,036 | 250,902 | 31,805,454 | 721,066 | (673) | (196,903) |
| 72 Schedule "M" Additions | 33,437,860 | (505,481) | - | 16,571,619 | - | 829,511 | - |
| 73 Schedule "M" Deductions | (8,583,880) | - | - | (968,522) | - | - | - |
| 74 Income Before Tax | (19,170,899) | (548,517) | (250,902) | (14,265,313) | (721,066) | (4,074,716) | 196,903 |
| 75 | | | | | | | |
| 76 State Income Taxes | (870,359) | (24,903) | (11,391) | (647,645) | (32,736) | (184,992) | 8,939 |
| 77 Taxable Income | (18,300,540) | (523,614) | (239,511) | (13,617,668) | (688,329) | (3,889,723) | 187,964 |
| 78 | | | | | | | |
| 79 Federal Income Taxes + Other | (3,843,113) | (109,959) | (50,297) | (2,859,710) | (144,549) | (816,842) | 39,472 |
| APPROXIMATE PRICE CHANGE | 145,016,168 | 152,663 | 890,027 | 112,823,796 | 2,557,844 | 5,078,659 | (698,476) |

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Tab 8 Adjustment Summary**

| | | 8.8 Pension and Other Post-retirement Plan Balances Removal | 8.9 Remove Rolling Hills | 8.10 Deer Creek Mine Adjustment | 8.11_R Emissions Control Investment Adjustment | 8.12 Transmission Project Adjustment | 8.13 Cholla Unit 4 Retirement | 8.14_R Miscellaneous Rate Base |
|---|---|---|---|---|---|---|---|---|
| 1 | Operating Revenues: | | | | | | | |
| 2 | General Business Revenues | - | - | - | - | - | - | - |
| 3 | Interdepartmental | - | - | - | - | - | - | - |
| 4 | Special Sales | - | - | - | - | - | - | - |
| 5 | Other Operating Revenues | - | - | - | - | - | - | - |
| 6 | Total Operating Revenues | - | - | - | - | - | - | - |
| 7 | | | | | | | | |
| 8 | Operating Expenses: | | | | | | | |
| 9 | Steam Production | - | - | (372,219) | - | - | - | - |
| 10 | Nuclear Production | - | - | - | - | - | - | - |
| 11 | Hydro Production | - | - | - | - | - | - | - |
| 12 | Other Power Supply | - | (311,183) | - | - | - | - | - |
| 13 | Transmission | - | - | - | - | - | - | - |
| 14 | Distribution | - | - | - | - | - | - | - |
| 15 | Customer Accounting | - | - | - | - | - | - | - |
| 16 | Customer Service & Info | - | - | - | - | - | - | - |
| 17 | Sales | - | - | - | - | - | - | - |
| 18 | Administrative & General | - | (76,991) | 797,657 | (977,980) | - | 732,144 | - |
| 19 | | | | | | | | |
| 20 | Total O&M Expenses | - | (388,174) | 425,438 | (977,980) | - | 732,144 | - |
| 21 | | | | | | | | |
| 22 | Depreciation | - | - | - | (138,078) | - | - | - |
| 23 | Amortization | - | - | - | - | - | 28,222 | - |
| 24 | Taxes Other Than Income | - | - | - | - | - | - | - |
| 25 | Income Taxes - Federal | 361,480 | 684,915 | 424,128 | 207,822 | 700 | (141,166) | (23,949) |
| 26 | Income Taxes - State | 81,865 | 155,114 | 96,053 | 47,066 | 159 | (31,970) | (5,424) |
| 27 | Income Taxes - Def Net | - | (482,459) | (518,633) | 25,435 | - | (9,931) | - |
| 28 | Investment Tax Credit Adj. | - | - | - | - | - | - | - |
| 29 | Misc Revenue & Expense | - | - | - | - | - | - | - |
| 30 | | | | | | | | |
| 31 | Total Operating Expenses: | 443,346 | (30,605) | 426,986 | (835,736) | 859 | 577,299 | (29,373) |
| 32 | | | | | | | | |
| 33 | Operating Rev For Return: | (443,346) | 30,605 | (426,986) | 835,736 | (859) | (577,299) | 29,373 |
| 34 | | | | | | | | |
| 35 | Rate Base: | | | | | | | |
| 36 | Electric Plant In Service | - | (52,478,373) | - | (979,001) | (182,000) | - | - |
| 37 | Plant Held for Future Use | - | - | - | - | - | - | - |
| 38 | Misc Deferred Debits | (61,547,849) | - | (17,450,145) | - | - | (603,848) | (2,773,151) |
| 39 | Elec Plant Acq Adj | - | - | - | - | - | - | - |
| 40 | Nuclear Fuel | (28,783,408) | - | - | - | - | - | - |
| 41 | Prepayments | - | - | - | - | - | - | - |
| 42 | Fuel Stock | - | - | - | - | - | - | 7,300,223 |
| 43 | Material & Supplies | - | - | - | - | - | - | - |
| 44 | Working Capital | 13,452 | 13,710 | 28,691 | (21,939) | 26 | 16,961 | (891) |
| 45 | Weatherization Loans | - | - | - | - | - | - | - |
| 46 | Misc Rate Base | - | - | - | - | - | - | - |
| 47 | | | | | | | | |
| 48 | Total Electric Plant: | (90,317,805) | (52,464,663) | (17,421,454) | (1,000,940) | (181,974) | (586,887) | 4,526,181 |
| 49 | | | | | | | | |
| 50 | Rate Base Deductions: | | | | | | | |
| 51 | Accum Prov For Deprec | - | (419,923) | - | - | 36,100 | - | - |
| 52 | Accum Prov For Amort | - | - | - | - | - | - | - |
| 53 | Accum Def Income Tax | 22,001,105 | 12,491,957 | 1,064,639 | 88,356 | 13,525 | (11,147) | - |
| 54 | Unamortized ITC | - | - | - | - | - | - | - |
| 55 | Customer Adv For Const | - | - | - | - | - | - | - |
| 56 | Customer Service Deposits | - | - | - | - | - | - | - |
| 57 | Misc Rate Base Deductions | - | - | - | - | - | - | - |
| 58 | | | | | | | | |
| 59 | Total Rate Base Deductions | 22,001,105 | 12,072,034 | 1,064,639 | 88,356 | 49,625 | (11,147) | - |
| 60 | | | | | | | | |
| 61 | Total Rate Base: | (68,316,700) | (40,392,629) | (16,356,814) | (912,584) | (132,349) | (598,035) | 4,526,181 |
| 62 | | | | | | | | |
| 63 | Return on Rate Base | 0.073% | 0.050% | 0.012% | 0.017% | 0.000% | -0.010% | -0.005% |
| 64 | | | | | | | | |
| 65 | Return on Equity | 0.147% | 0.100% | 0.024% | 0.035% | 0.000% | -0.021% | -0.010% |
| 66 | | | | | | | | |
| 67 | TAX CALCULATION: | | | | | | | |
| 68 | Operating Revenue | - | 388,174 | (425,438) | 1,116,058 | - | (760,367) | - |
| 69 | Other Deductions | - | - | - | - | - | - | - |
| 70 | Interest (AFUDC) | - | - | - | - | - | - | - |
| 71 | Interest | (1,803,200) | (1,066,152) | (431,734) | (24,087) | (3,493) | (15,785) | 119,467 |
| 72 | Schedule "M" Additions | - | - | (1,708,971) | (138,078) | - | 40,392 | - |
| 73 | Schedule "M" Deductions | - | (1,962,286) | (3,818,384) | (34,629) | - | - | - |
| 74 | Income Before Tax | 1,803,200 | 3,416,613 | 2,115,708 | 1,036,696 | 3,493 | (704,189) | (119,467) |
| 75 | | | | | | | | |
| 76 | State Income Taxes | 81,865 | 155,114 | 96,053 | 47,066 | 159 | (31,970) | (5,424) |
| 77 | Taxable Income | 1,721,335 | 3,261,498 | 2,019,655 | 989,630 | 3,335 | (672,219) | (114,043) |
| 78 | | | | | | | | |
| 79 | Federal Income Taxes + Other | 361,480 | 684,915 | 424,128 | 207,822 | 700 | (141,166) | (23,949) |
| | APPROXIMATE PRICE CHANGE | (6,396,509) | (4,184,086) | (1,090,776) | (1,241,584) | (12,392) | 731,679 | 423,787 |

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Tab 8 Adjustment Summary**

| | | 8.15 | 8.16 | 8.17 | 8.18_R | 8.19 | 8.20 |
|---|---|---|---|---|---|---|---|
| | | Carbon Plant Closure | Removal of Wildfire Mitigation Capital Rate Base | New Wind Generation Capital Additions_CONF | Wildfire Restoration Costs Deferral Amortization | Aeolus Substation Settlement | Klamath Regulatory Asset |
| 1 | Operating Revenues: | | | | | | |
| 2 | General Business Revenues | - | - | - | - | - | - |
| 3 | Interdepartmental | - | - | - | - | - | - |
| 4 | Special Sales | - | - | - | - | - | - |
| 5 | Other Operating Revenues | - | - | - | - | - | - |
| 6 | Total Operating Revenues | - | - | - | - | - | - |
| 7 | | | | | | | |
| 8 | Operating Expenses: | | | | | | |
| 9 | Steam Production | - | - | - | - | - | - |
| 10 | Nuclear Production | - | - | - | - | - | - |
| 11 | Hydro Production | - | - | - | - | - | (563,449) |
| 12 | Other Power Supply | - | - | 1,210,193 | - | - | - |
| 13 | Transmission | - | - | - | - | - | - |
| 14 | Distribution | - | - | - | - | - | - |
| 15 | Customer Accounting | - | - | - | - | - | - |
| 16 | Customer Service & Info | - | - | - | - | - | - |
| 17 | Sales | - | - | - | - | - | - |
| 18 | Administrative & General | - | - | - | - | - | - |
| 19 | | | | | | | |
| 20 | Total O&M Expenses | - | - | 1,210,193 | - | - | (563,449) |
| 21 | | | | | | | |
| 22 | Depreciation | - | - | 5,851,507 | - | - | - |
| 23 | Amortization | (1,615,751) | - | - | 18,878,341 | - | 343,117 |
| 24 | Taxes Other Than Income | - | - | - | - | - | - |
| 25 | Income Taxes - Federal | 298,065 | 311,922 | (2,149,844) | 34,919 | 6,435 | 83,345 |
| 26 | Income Taxes - State | 67,504 | 70,642 | (486,880) | 7,908 | 1,457 | 18,875 |
| 27 | Income Taxes - Def Net | 44,130 | (281,746) | - | (4,675,176) | - | (41,144) |
| 28 | Investment Tax Credit Adj. | - | - | - | - | - | - |
| 29 | Misc Revenue & Expense | - | - | - | - | - | - |
| 30 | | | | | | | |
| 31 | Total Operating Expenses: | (1,206,052) | 100,817 | 4,424,976 | 14,245,991 | 7,893 | (159,257) |
| 32 | | | | | | | |
| 33 | Operating Rev For Return: | 1,206,052 | (100,817) | (4,424,976) | (14,245,991) | (7,893) | 159,257 |
| 34 | | | | | | | |
| 35 | Rate Base: | | | | | | |
| 36 | Electric Plant In Service | - | (16,976,982) | 139,047,122 | (1,361) | - | - |
| 37 | Plant Held for Future Use | - | - | - | - | - | - |
| 38 | Misc Deferred Debits | (477,793) | - | - | (1,878,302) | - | (1,392,013) |
| 39 | Elec Plant Acq Adj | - | - | - | - | - | - |
| 40 | Nuclear Fuel | - | - | - | - | - | - |
| 41 | Prepayments | - | - | - | - | - | - |
| 42 | Fuel Stock | - | - | - | - | - | - |
| 43 | Material & Supplies | - | - | - | - | - | - |
| 44 | Working Capital | 11,092 | 11,607 | (43,283) | 1,299 | 239 | (13,994) |
| 45 | Weatherization Loans | - | - | - | - | - | - |
| 46 | Misc Rate Base | - | - | - | - | - | - |
| 47 | | | | | | | |
| 48 | Total Electric Plant: | (466,701) | (16,965,375) | 139,003,839 | (1,878,363) | 239 | (1,406,007) |
| 49 | | | | | | | |
| 50 | Rate Base Deductions: | | | | | | |
| 51 | Accum Prov For Deprec | - | 334,168 | (243,813) | - | (1,613,049) | - |
| 52 | Accum Prov For Amort | - | 276,415 | - | - | - | - |
| 53 | Accum Def Income Tax | (642,408) | 819,360 | - | 461,811 | 396,594 | 342,249 |
| 54 | Unamortized ITC | - | - | - | - | - | - |
| 55 | Customer Adv For Const | - | - | - | - | - | - |
| 56 | Customer Service Deposits | - | - | - | - | - | - |
| 57 | Misc Rate Base Deductions | (807,875) | - | - | - | - | - |
| 58 | | | | | | | |
| 59 | Total Rate Base Deductions | (1,450,284) | 1,429,943 | (243,813) | 461,811 | (1,216,455) | 342,249 |
| 60 | | | | | | | |
| 61 | Total Rate Base: | (1,916,985) | (15,535,432) | 138,760,027 | (1,416,552) | (1,216,216) | (1,063,759) |
| 62 | | | | | | | |
| 63 | Return on Rate Base | 0.026% | 0.017% | -0.252% | -0.267% | 0.001% | 0.004% |
| 64 | | | | | | | |
| 65 | Return on Equity | 0.051% | 0.035% | -0.505% | -0.534% | 0.002% | 0.008% |
| 66 | | | | | | | |
| 67 | TAX CALCULATION: | | | | | | |
| 68 | Operating Revenue | 1,615,751 | - | (7,061,701) | (18,878,341) | - | 220,332 |
| 69 | Other Deductions | - | - | - | - | - | - |
| 70 | Interest (AFUDC) | - | - | - | - | - | - |
| 71 | Interest | (50,598) | (410,053) | 3,662,532 | (37,390) | (32,102) | (28,078) |
| 72 | Schedule "M" Additions | (179,487) | (486,783) | - | 19,015,139 | - | - |
| 73 | Schedule "M" Deductions | - | (1,632,714) | - | - | - | (167,345) |
| 74 | Income Before Tax | 1,486,862 | 1,555,984 | (10,724,233) | 174,188 | 32,102 | 415,755 |
| 75 | | | | | | | |
| 76 | State Income Taxes | 67,504 | 70,642 | (486,880) | 7,908 | 1,457 | 18,875 |
| 77 | Taxable Income | 1,419,359 | 1,485,342 | (10,237,352) | 166,279 | 30,644 | 396,880 |
| 78 | | | | | | | |
| 79 | Federal Income Taxes + Other | 298,065 | 311,922 | (2,149,844) | 34,919 | 6,435 | 83,345 |
| | APPROXIMATE PRICE CHANGE | (1,853,264) | (1,454,588) | 20,307,436 | 19,423,671 | (113,875) | (327,845) |

**PacifiCorp** PAGE 8.1_R
**Oregon General Rate Case - December 2025**
**Cash Working Capital**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Expense:** | | | | | | | |
| *Cash Working Capital* | *CWC* | *3* | *1,147,761* | *OR* | *Situs* | *1,147,761* | *Below* |
| | | | | | | | |
| **Adjustment Detail:** | | | | | | | |
| Cash Working Capital June 2023 - Unadjusted | | | 86,606,808 | | | 35,213,620 | 2.28_R |
| Cash Working Capital December 2025 - Normalized | | | 84,900,755 | | | 36,361,381 | 2.28_R |
| Adjustment: | | | (1,706,053) | | | 1,147,761 | |

**Description of Adjustment:**

This adjustment is necessary to compute the cash working capital for the normalized results of operations in this filing. Cash working capital is calculated by taking total operation and maintenance expense allocated to the jurisdiction and adding its share of allocated taxes, including state and federal income taxes and taxes other than income. This total is divided by the number of days in the year to determine the Company's average daily cost of service. The daily cost of service is multiplied by net lag days to produce the adjusted cash working capital balance. Net lag days for Oregon are calculated using the Company's 2022 lead lag study. A separate column is not shown for adjustment 8.1 on page 8.0.2 as the cash working capital component is calculated and shown on the adjustment summary pages for each of the adjustments individually.

*This adjustment has been modified for Cash Working Capital impacts as a result of corrections and updates to adjustments made in Reply.*

**PacifiCorp**
**Cash Working Capital**
**Twelve Months Ending December 31, 2025**

| Lead/Lag Study as of 12/22 | Total | California | Oregon | Washington | Wyoming | Wy-PPL | Utah | Idaho | Wy-UPL | FERC |
|---|---|---|---|---|---|---|---|---|---|---|
| Revenue Lag Days | 41.52 | 42.52 | 48.17 | 41.27 | 41.98 | 41.98 | 44.89 | 34.38 | 41.98 | 35.62 |
| Expense Lag Days | 35.72 | 40.95 | 37.10 | 35.20 | 34.97 | 34.97 | 37.17 | 38.87 | 34.97 | 35.10 |
| Net Lag Days | 5.80 | 1.58 | 11.07 | 6.07 | 7.01 | 7.01 | 7.72 | -4.49 | 7.01 | 0.53 |
| O&M Expense | 3,669,391,788 | 81,026,399 | 1,129,865,185 | 291,683,385 | 542,738,004 | 474,273,864 | 1,773,376,878 | 228,747,316 | 68,464,141 | 1 |
| Taxes Other than Income | 249,409,461 | 6,558,470 | 100,593,896 | 14,679,149 | 27,578,195 | 24,195,097 | 89,068,876 | 10,930,874 | 3,383,097 | 0 |
| Federal Income Tax | (111,275,580) | (5,612,401) | (38,449,492) | (16,334,813) | (56,266,249) | (51,608,745) | (136,627,306) | (12,925,311) | (4,657,505) | 2,878,039 |
| State Income Tax | 37,325,856 | (508,540) | 6,408,557 | 447,094 | (5,114,402) | (5,004,409) | (6,090,428) | 170,525 | (109,992) | 651,796 |
| Total | 3,844,851,525 | 81,463,928 | 1,198,418,146 | 290,474,815 | 508,935,548 | 441,855,807 | 1,719,728,020 | 226,923,404 | 67,079,741 | 3,529,836 |
| Divided by Days in Year | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 |
| Avg. Daily Cost of Service | 10,533,840 | 223,189 | 3,283,337 | 795,821 | 1,394,344 | 1,210,564 | 4,711,584 | 621,708 | 183,780 | 9,671 |
| Net Lag Days | 5.80 | 1.58 | 11.07 | 6.07 | 7.01 | 7.01 | 7.72 | (4.49) | 7.01 | 0.53 |
| Cash Working Capital | **84,900,755** | 351,994 | **36,361,381** | 4,830,636 | 9,772,729 | 8,484,644 | 36,367,491 | (2,788,594) | 1,288,085 | 5,118 |
| | **Ref. 8.1_R** | | **Ref. 8.1_R** | | | | | | | |

Exhibit PAC/3302
Cheung/109

**PacifiCorp** PAGE 8.6_R
**Oregon General Rate Case - December 2025**
**Regulatory Assets & Liabilities Amortization**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Revenues:** | | | | | | | |
| FERC OATT Deferral Refund | 456 | 3 | (4,075,388) | OR | Situs | (4,075,388) | 8.6.4 |
| **Adjustment to Expense:** | | | | | | | |
| *Oregon Distribution System Plan* | *592* | *3* | *829,511* | *OR* | *Situs* | *829,511* | *8.6.6_R* |
| **Adjustment to Rate Base:** | | | | | | | |
| Elec. Plant Acq. Acc. Amort. | 115 | 3 | (75,351) | SG | 26.884% | (20,258) | 8.6.1 |
| **Adjustment to Tax:** | | | | | | | |
| *Schedule M Adjustment* | *SCHMAT* | *3* | *829,511* | *OR* | *Situs* | *829,511* | *8.6.6_R* |
| *Deferred Income Tax Expense* | *41110* | *3* | *(203,949)* | *OR* | *Situs* | *(203,949)* | *8.6.6_R* |

**Description of Adjustment:**

This adjustment removes from results the amortization of deferred expenses from the Post-2017 FERC OATT Revenue Deferral balance approved in the Company's prior general rate case, Docket UE 374 as the balance is fully amortized as of December 2023.

This adjustment also adds in the proposed amortizations of deferrals including Oregon Wildfire Damaged Assets Net Book Value Deferral, Oregon Distribution System Plan deferral, and Insurance Premiums deferral. The Company is proposing a three year amortization for these balances, beginning the effective date of this general rate case, January 1, 2025.

Finally, this adjustment also walks forward Electric Plant Acquisition in the base period (12 months ended June 2023) to pro forma period levels (12 months ending December 2025).

*This adjustment has been updated to reflect the corrections identified in OPUC Data Request 494.*

**PacifiCorp** 
**Oregon General Rate Case - December 2025**
**Regulatory Assets & Liabilities Amortization**
**Oregon Distribution System Plan**

| | Amortization |
|---|---|
| Base Period Amount (below) | - |
| Pro Forma Amount (below) | (829,511) |
| Adjustment: | **(829,511)** |
| | **Ref. 8.6_R** |

| | | Opening Bal. | Accrual | Amortization | Interest[1,2] | Ending Bal. |
|---|---|---|---|---|---|---|
| 2022 | June | - | - | - | - | - |
| | July | - | 154,045 | - | 458 | 154,504 |
| | August | 154,504 | 186,304 | - | 1,473 | 342,281 |
| | September | 342,281 | 55,781 | - | 2,202 | 400,264 |
| | October | 400,264 | 90,783 | - | 2,651 | 493,698 |
| | November | 493,698 | 26,700 | - | 3,016 | 523,413 |
| | December | 523,413 | 403,735 | - | 4,314 | 931,462 |
| 2023 | January | 931,462 | - | - | 5,518 | 936,980 |
| | February | 936,980 | 152,469 | - | 6,002 | 1,095,451 |
| | March | 1,095,451 | 107,115 | - | 6,807 | 1,209,373 |
| | April | 1,209,373 | 100,739 | - | 7,463 | 1,317,574 |
| | May | 1,317,574 | 61,186 | - | 7,986 | 1,386,747 |
| | June | 1,386,747 | 34,939 | - | 8,318 | 1,430,004 |
| | | | **Base Period Amort =** | **-** | | |
| | July | 1,430,004 | 73,824 | - | 8,690 | 1,512,518 |
| | August | 1,512,518 | 107,081 | - | 9,277 | 1,628,876 |
| | September | 1,628,876 | 58,557 | - | 9,823 | 1,697,256 |
| | October | 1,697,256 | 74,398 | - | 10,275 | 1,781,929 |
| | November | 1,781,929 | 110,625 | - | 10,884 | 1,903,437 |
| | December | 1,903,437 | 225,224 | - | 11,943 | 2,140,604 |
| 2024 | January | 2,140,604 | - | - | 12,681 | 2,153,284 |
| | February | 2,153,284 | - | - | 12,756 | 2,166,040 |
| | March | 2,166,040 | - | - | 12,831 | 2,178,872 |
| | April | 2,178,872 | - | - | 12,907 | 2,191,779 |
| | May | 2,191,779 | - | - | 12,984 | 2,204,763 |
| | June | 2,204,763 | - | - | 13,061 | 2,217,824 |
| | July | 2,217,824 | - | - | 13,138 | 2,230,962 |
| | August | 2,230,962 | - | - | 13,216 | 2,244,178 |
| | September | 2,244,178 | - | - | 13,294 | 2,257,473 |
| | October | 2,257,473 | - | - | 13,373 | 2,270,846 |
| | November | 2,270,846 | - | - | 13,452 | 2,284,298 |
| | December | 2,284,298 | - | - | 13,532 | 2,297,830 |
| 2025 | January | 2,297,830 | - | (69,126) | 10,185 | 2,238,889 |
| | February | 2,238,889 | - | (69,126) | 9,919 | 2,179,682 |
| | March | 2,179,682 | - | (69,126) | 9,653 | 2,120,209 |
| | April | 2,120,209 | - | (69,126) | 9,385 | 2,060,469 |
| | May | 2,060,469 | - | (69,126) | 9,117 | 2,000,460 |
| | June | 2,000,460 | - | (69,126) | 8,847 | 1,940,180 |
| | July | 1,940,180 | - | (69,126) | 8,575 | 1,879,630 |
| | August | 1,879,630 | - | (69,126) | 8,303 | 1,818,806 |
| | September | 1,818,806 | - | (69,126) | 8,029 | 1,757,710 |
| | October | 1,757,710 | - | (69,126) | 7,754 | 1,696,338 |
| | November | 1,696,338 | - | (69,126) | 7,478 | 1,634,690 |
| | December | 1,634,690 | - | (69,126) | 7,201 | 1,572,765 |
| | | | **Pro Forma Amort =** | **(829,511)** | | |

| SCHMAT | 41110 |
|---|---|
| - | - |
| 69,126 | (16,996) |
| 69,126 | (16,996) |
| 69,126 | (16,996) |
| 69,126 | (16,996) |
| 69,126 | (16,996) |
| 69,126 | (16,996) |
| 69,126 | (16,996) |
| 69,126 | (16,996) |
| 69,126 | (16,996) |
| 69,126 | (16,996) |
| 69,126 | (16,996) |
| **829,511** | **(203,949)** |
| **Ref. 8.6_R** | **Ref. 8.6_R** |

Note:
1. Interest rate in deferral period per approved WACC from UE-374 prior to 1/1/2023 and from UE-399 effective 1/1/2023.

| | UE-374 | UE-399 |
|---|---|---|
| WACC | 7.14% | 7.11% |

2. Interest accrual at Modified Blended Treasury Rate as of date of the Commission's approval of the amortization (i.e. Dec 2024).

| | 2024 | |
|---|---|---|
| MBTR | 5.400% | Ref UM-1147 |

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Regulatory Assets & Liabilities Amortization**
**Oregon Distribution System Plan**
**Company's response to OPUC Data Request 494**

UE 433 / PacifiCorp
May 15, 2024
OPUC Data Request 494

**OPUC Data Request 494**

**UM 2220 Deferral** – Please provide a workpaper providing all items placed into the UM 2220 deferral. With each item, please include:

(a) A description of the item
(b) The dollar value of the item
(c) The date that the cost of the item was incurred
(d) An indicator for whether the item is a part of the Company's annual ongoing DSP costs or it is a one-time cost.

**Response to OPUC Data Request 494**

In preparing the response to this data request, the Company discovered that historical accrual balance of distribution system planning (DSP) expenses included in the Company's request for amortization reflected a minor clerical error that resulted in the accrued balance through calendar 2023 to be overstated by approximately $61,000 on an Oregon-allocated basis. The Company will reflect this correction in its reply filing. Correcting for this error would result in a reduction to the price change request in this general rate case (GRC) of approximately $27,000.

Please refer to Attachment OPUC 494 which provides the work papers requested summarizing all items placed into the Docket UM 2220 deferral for calendar years 2022 and 2023. Note: the values in Attachment OPUC 494 have been adjusted to correct the clerical error identified above.

**PacifiCorp** PAGE 8.11_R
**Oregon General Rate Case - December 2025**
**Emissions Control Investment Adjustment**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Rate Base:** | | | | | | | |
| Hunter Clean Air Disallowance | 312 | 1 | (3,641,553) | SG | 26.884% | (979,001) | 8.11.1 |
| **Adjustment to Expense:** | | | | | | | |
| Hunter Clean Air Disallowance | 403SP | 1 | (513,605) | SG | 26.884% | (138,078) | 8.11.1 |
| **Adjustment to Return:** | | | | | | | |
| *JB U3 & U4 Return Disallowance* | *930* | *1* | *(1,196,832)* | *OR* | *Situs* | *(1,196,832)* | *8.11.2_R* |
| *JB U3 & U4 Return Disallowance* | *930* | *3* | *218,852* | *OR* | *Situs* | *218,852* | *8.11.2_R* |
| | | | (977,980) | | | (977,980) | |
| **Adjustment to Tax:** | | | | | | | |
| Schedule M Adjustment | SCHMAT | 1 | (513,605) | SG | 26.884% | (138,078) | |
| Schedule M Adjustment | SCHMDT | 1 | (128,808) | SG | 26.884% | (34,629) | |
| Deferred Income Tax Expense | 41110 | 1 | 126,278 | SG | 26.884% | 33,949 | |
| Deferred Income Tax Expense | 41010 | 1 | (31,670) | SG | 26.884% | (8,514) | |
| Accumulated Def Inc Tax Balance | 282 | 1 | 328,655 | SG | 26.884% | 88,356 | |

**Description of Adjustment:**

This adjustment removes 10% of the net book value of the Hunter U1 U1 Clean Air - PM & NOX LNB Clean Air equipment projects and reduces return on Jim Bridger Unit 3 & 4 SCR projects to authorized return equal to long-term debt cost as ordered in UE 374, Order No. 20-473.

*The corresponding calculation to remove the return disallowance from revenue requirement needed to be revised to reflect the updated return on equity and cost of debt in Reply.*

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Emissions Control Investment Adjustment**
**Jim Bridger Unit 3 & 4 SCR Return Disallowance**

**Restating Adjustment**

| | Total Co. | OR Allocated |
|---|---|---|
| Net Book Value - Year End June 2023 | 118,448,589 | 31,843,905 |
| | | |
| Pre-Tax Rate of Return | 9.04% | 9.04% |
| Return on Rate Base Rate of Return | 10,705,898 | 2,878,190 |
| | | |
| Return - Cost of Long-Term Debt | 5.28% | 5.28% |
| Return on Rate Base Cost of Debt | 6,254,086 | 1,681,358 |
| | | |
| Approx. Revenue Requirement Reduction | (4,451,812) | **(1,196,832)** |
| | | **Ref 8.11_R** |

System Generation Factor (SG) 26.884%

**Pro Forma Adjustment**

| | Total Co. | OR Allocated |
|---|---|---|
| Net Book Value - Year End December 2024 | 96,789,135 | 26,020,943 |
| | | |
| Pre-Tax Rate of Return | 9.04% | 9.04% |
| Return on Rate Base Rate of Return | 8,748,222 | 2,351,886 |
| | | |
| Return - Cost of Long-Term Debt | 5.28% | 5.28% |
| Return on Rate Base Cost of Debt | 5,110,466 | 1,373,906 |
| | | |
| Approx. Revenue Requirement Reduction | (3,637,756) | (977,980) |
| **Pro Forma Adj. to Revenue Requirement Red.** | | **218,852** |
| | | **Ref 8.11_R** |

System Generation Factor (SG) 26.884%

Exhibit PAC/3302
Cheung/114

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Emissions Control Investment Adjustment**
**Summary of Variables**
**Capital Structure and Costs**

| | Capital Structure | Embedded Cost | Weighted Cost | Tax Net-to-Gross Bump-up | Pre-Tax Revenue Requirement |
|---|---|---|---|---|---|
| Debt | 49.99% | 5.28% | 2.64% | | 2.64% |
| Preferred | 0.01% | 6.75% | 0.00% | 132.60% | 0.00% |
| Common | 50.00% | 9.65% | 4.83% | 132.60% | 6.40% |
| Total | 100.00% | | 7.47% | | 9.04% |

| | |
|---|---|
| Merged Effective Tax Rate | 24.587% |
| Pre-Tax Bump-up Factor | 132.60% |

**2020 Protocol Allocation Factors**

| | |
|---|---|
| Forecast 2025 SG Factor | 26.884% |

**PacifiCorp** PAGE 8.14_R
**Oregon General Rate Case - December 2025**
**Miscellaneous Rate Base**

| Adjustment to Rate Base: | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| *1 - Fuel Stock - Pro Forma* | *151* | *3* | *29,277,182* | *SE* | *26.339%* | *7,711,352* | *8.14.1_R* |
| *1 - Fuel Stock - Working Capital Deposit* | *25316* | *3* | *875,308* | *SE* | *26.339%* | *230,548* | *8.14.1_R* |
| *1 - Fuel Stock - Working Capital Deposit* | *25317* | *3* | *(2,436,213)* | *SE* | *26.339%* | *(641,677)* | *8.14.1_R* |
| *2 - Prepaid Overhauls* | *186M* | *3* | *(10,315,186)* | *SG* | *26.884%* | *(2,773,151)* | *8.14.1_R* |

**Description of Adjustment:**

1 - Fuel stock levels for the 13 month average year ending December 2025 are projected to be lower than the year ended June 2023 levels due to an increase in the amount of coal stockpiled. The adjustment also reflects the change in projected working capital deposits.

2 - Balances for prepaid overhauls at the Lake Side, Chehalis and Currant Creek gas plants are walked forward to reflect payments and transfers of capital to electric plant in service during the year ending December 2025.

*This adjustment has been revised to reflect corrections and updates as described in the reply testimony of Company witness Sherona L. Cheung and James Owen.*

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Miscellaneous Rate Base**

| 1 - Coal Fuel Stock Balances by Plant | Account | Factor | Actuals Jun-2023 EOP Balance | Pro Forma Dec-2025 13 Mth. Avg. Balance | Adj. to 13 Mth. Avg. Balance | |
|---|---|---|---|---|---|---|
| Jim Bridger | 151 | SE | 36,657,668 | 45,232,433 | 8,574,765 | |
| Cholla | 151 | SE | - | - | - | |
| Colstrip | 151 | SE | 2,092,828 | 2,044,088 | (48,740) | |
| Craig | 151 | SE | 7,582,296 | 9,871,296 | 2,289,000 | |
| Hayden | 151 | SE | 2,644,532 | 2,868,649 | 224,117 | |
| Hunter | 151 | SE | 24,158,107 | 63,296,625 | 39,138,518 | |
| Huntington | 151 | SE | 22,463,774 | 21,148,562 | (1,315,212) | |
| Dave Johnston | 151 | SE | 15,026,113 | 15,502,897 | 476,784 | |
| Naughton | 151 | SE | 21,629,537 | 6,265,181 | (15,364,356) | |
| Rock Garden | 151 | SE | 4,697,694 | - | (4,697,694) | |
| Total | | | 136,952,549 | 166,229,731 | **29,277,182** | **Ref. 8.14_R** |

| 1 - Working Capital Deposits | Account | Factor | Actuals Jun-2023 EOP Balance | Pro Forma Dec-2025 13 Mth. Avg. Balance | Adj. to 13 Mth. Avg. Balance | |
|---|---|---|---|---|---|---|
| UAMPS Working Capital Deposit | 25316 | SE | (1,762,000) | (886,692) | **875,308** | **Ref. 8.14_R** |
| DPEC Working Capital Deposit | 25317 | SE | (2,802,703) | (5,238,916) | **(2,436,213)** | **Ref. 8.14_R** |

| 2 - Overhaul Prepayments by Plant | Account | Factor | Actuals Jun-2023 EOP Balance | Pro Forma Dec-2025 13 Mth. Avg. Balance | Adj. to 13 Mth. Avg. Balance | |
|---|---|---|---|---|---|---|
| Lake Side 1 | 186M | SG | 24,823,813 | 7,771,815 | (17,051,998) | |
| Chehalis | 186M | SG | 10,640,887 | 24,732,549 | 14,091,662 | |
| Currant Creek | 186M | SG | 10,552,675 | 23,133,374 | 12,580,699 | |
| Lake Side 2 | 186M | SG | 33,049,760 | 11,678,664 | (21,371,095) | |
| Chehalis O&M | 186M | SG | 1,640,642 | 2,392,025 | 751,383 | |
| Currant Creek O&M | 186M | SG | 420,580 | 1,104,744 | 684,163 | |
| Total | | | 81,128,357 | 70,813,171 | **(10,315,186)** | **Ref. 8.14_R** |

**PacifiCorp** PAGE 8.18_R
**Oregon General Rate Case - December 2025**
**Wildfire Restoration Costs Deferral Amortization**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Expense:** | | | | | | | |
| *Wildfire Restoration Capital* | *407* | *3* | *18,268,715* | *OR* | *Situs* | *18,268,715* | *8.18.1_R* |
| Damaged Asset NBV | 407 | 3 | 609,626 | OR | Situs | 609,626 | 8.18.2 |
| **Adjustment to Rate Base:** | | | | | | | |
| Damaged Asset NBV | 182M | 3 | (1,878,302) | OR | Situs | (1,878,302) | 8.18.2 |
| *Remove Rate Base - OPUC 588* | *361* | *1* | *(1,361)* | *OR* | *Situs* | *(1,361)* | |
| **Adjustment to Tax:** | | | | | | | |
| Damaged Asset - Schedule M | SCHMAT | 3 | 746,424 | OR | Situs | 746,424 | |
| Damaged Asset - Def. Inc. Tax Exp. | 41110 | 3 | (183,520) | OR | Situs | (183,520) | |
| Damaged Asset - ADIT | 283 | 3 | 461,811 | OR | Situs | 461,811 | |
| *Wildfire Restoration - Schedule M* | *SCHMAT* | *3* | *18,268,715* | *OR* | *Situs* | *18,268,715* | |
| *Wildfire Restoration - Def. Inc. Tax Exp.* | *41110* | *3* | *(4,491,656)* | *OR* | *Situs* | *(4,491,656)* | |

**Description of Adjustment:**

This adjustment adds into test period results the amortization deferred revenue requirement associated with damage restoration from the 2020 Labor Day wildfires, net of deferred revenue requirement amounts associated with plant no longer used and useful. (Docket No. UM 2116).

This adjustment proposes/requests to begin amortization of the deferred revenue requirement for the wildfire damage net book value and capital additions over a three year period, starting 1/1/2025.

*This reply adjustment corrects a formula on page 8.18.1 where the content in cell C13 was inadvertently deleted. The adjustment also removes Books & Subscriptions/Dist amount recorded in error, identified as in OPUC Data Request 587, updates depreciation expense for the time period costs were not allowed to be deferred, removes a rate base amount identified in OPUC Data Request 588, and reflects an offset to deferred costs for revenue requirement of damaged plant as identified in OPUC Data Request 584. For further details, please refer to the reply testimony of Company witness Sherona L. Cheung.*

**PacifiCorp** 
**Oregon General Rate Case - December 2025**
**Wildfire Restoration Costs Deferral Amortization**
**Restoration Costs Deferral Summary**

| | Amortization |
|---|---|
| Base Period Amount (below) | - |
| Pro Forma Amount (below) | 18,268,715 |
| Adjustment: | **18,268,715** |
| | **Ref. 8.18_R** |

| | | | Accrual | | Damaged Plant | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Opening Bal. | Capital[1] | O&M[1] | Net Book Offset | Amortization | Interest[2,3] | Ending Bal. | | | |
| 2020 | September | - | 214,018 | 1,236,820 | (8,635) | - | 680 | 1,442,883 | | | |
| | October | *1,442,883* | 401,284 | 158,695 | (8,635) | - | 10,438 | 2,004,664 | | | |
| | November | 2,004,664 | 401,284 | 107,431 | (8,635) | - | 14,006 | 2,518,749 | | | |
| | December | 2,518,749 | 401,284 | 654,107 | (8,635) | - | 16,174 | 3,581,680 | | | |
| 2021 | January | 3,581,680 | 401,284 | 99,343 | (15,815) | - | 22,496 | 4,088,988 | | | |
| | February | 4,088,988 | 401,284 | 11,183 | (15,815) | - | 25,513 | 4,511,155 | | | |
| | March | 4,511,155 | 401,284 | (34,900) | (15,815) | - | 28,024 | 4,889,749 | | | |
| | April | 4,889,749 | 401,284 | 7,353 | (15,815) | - | 30,276 | 5,312,848 | | | |
| | May | 5,312,848 | 401,284 | 33,244 | (15,815) | - | 32,792 | 5,764,354 | | | |
| | June | 5,764,354 | 401,284 | 3,065 | (15,815) | - | 35,478 | 6,188,366 | | | |
| | July | 6,188,366 | 401,284 | 147 | (15,815) | - | 38,000 | 6,611,983 | | | |
| | August | 6,611,983 | 401,284 | - | (15,815) | - | 40,519 | 7,037,972 | | | |
| | September | 7,037,972 | 887,382 | 115 | (15,815) | - | 44,498 | 7,954,153 | | | |
| | October | 7,954,153 | 887,382 | 1,437 | (15,815) | - | 49,948 | 8,877,105 | | | |
| | November | 8,877,105 | 887,382 | 575 | (15,815) | - | 55,437 | 9,804,684 | | | |
| | December | 9,804,684 | 887,382 | (900) | (15,815) | - | 60,954 | 10,736,305 | | | |
| 2022 | January | 10,736,305 | 887,382 | 283 | (15,815) | - | 66,495 | 11,674,650 | | | |
| | February | 11,674,650 | 887,382 | 397 | (15,815) | - | 72,076 | 12,618,691 | **SCHAT** | **41110** | **ADIT -190** |
| | March | 12,618,691 | 887,382 | 2,193 | (15,815) | - | 77,691 | 13,570,142 | | | (3,336,437) |
| | April | 13,570,142 | 887,382 | (577) | (15,815) | - | 83,350 | 14,524,482 | - | - | (3,571,076) |
| | May | 14,524,482 | 887,382 | 8,495 | (15,815) | - | 89,026 | 15,493,570 | - | - | (3,809,342) |
| | June | 15,493,570 | 887,382 | 6,044 | (15,815) | - | 94,789 | 16,465,970 | - | - | (4,048,422) |
| | July | 16,465,970 | 887,382 | 525 | (15,815) | - | 100,573 | 17,438,636 | - | - | (4,287,568) |
| | August | 17,438,636 | 887,382 | 2,390 | (15,815) | - | 106,358 | 18,418,951 | - | - | (4,528,594) |
| | September | 18,418,951 | 959,874 | (13) | (15,815) | - | 112,404 | 19,475,402 | - | - | (4,788,339) |
| | October | 19,475,402 | 959,874 | 970 | (15,815) | - | 118,688 | 20,539,120 | - | - | (5,049,871) |
| | November | 20,539,120 | 959,874 | (1,910) | (15,815) | - | 125,014 | 21,606,284 | - | - | (5,312,251) |
| | December | 21,606,284 | 959,874 | - | (15,815) | - | 131,361 | 22,681,705 | - | - | (5,576,660) |
| 2023 | January | 22,681,705 | 959,874 | 58 | (9,525) | - | 137,208 | 23,769,320 | - | - | (5,844,068) |
| | February | 23,769,320 | 959,874 | 70 | (9,525) | - | 143,651 | 24,863,390 | - | - | (6,113,062) |
| | March | 24,863,390 | 959,874 | | (9,525) | - | 150,132 | 25,963,871 | - | - | (6,383,633) |
| | April | 25,963,871 | 959,874 | | (9,525) | - | 156,651 | 27,070,871 | - | | (6,655,807) |
| | May | 27,070,871 | 959,874 | | (9,525) | - | 163,209 | 28,184,430 | - | | (6,929,593) |
| | June | 28,184,430 | 959,874 | | (9,525) | - | 169,805 | 29,304,584 | - | | (7,205,001) |
| | July | 29,304,584 | 959,874 | | (9,525) | - | 176,441 | 30,431,375 | - | | (7,482,040) |
| | August | 30,431,375 | 959,874 | | (9,525) | - | 183,116 | 31,564,840 | - | | (7,760,721) |
| | September | 31,564,840 | 951,453 | | (9,525) | - | 189,806 | 32,696,574 | - | | (8,038,976) |
| | October | 32,696,574 | 951,453 | | (9,525) | - | 196,510 | 33,835,011 | - | | (8,318,879) |
| | November | 33,835,011 | 951,453 | | (9,525) | - | 203,254 | 34,980,193 | - | | (8,600,440) |
| | December | 34,980,193 | 951,453 | | (9,525) | - | 210,038 | 36,132,158 | - | | (8,883,669) |
| 2024 | January | 36,132,158 | 951,453 | | (9,525) | - | 216,862 | 37,290,948 | - | | (9,168,576) |
| | February | 37,290,948 | 951,453 | | (9,525) | - | 223,727 | 38,456,603 | - | | (9,455,171) |
| | March | 38,456,603 | 951,453 | | (9,525) | - | 230,632 | 39,629,162 | - | | (9,743,464) |
| | April | 39,629,162 | 951,453 | | (9,525) | - | 237,578 | 40,808,668 | - | | (10,033,464) |
| | May | 40,808,668 | 951,453 | | (9,525) | - | 244,565 | 41,995,161 | - | | (10,325,182) |
| | June | 41,995,161 | 951,453 | | (9,525) | - | 251,594 | 43,188,683 | - | | (10,618,629) |
| | July | 43,188,683 | 951,453 | | (9,525) | - | 258,664 | 44,389,275 | - | | (10,913,813) |
| | August | 44,389,275 | 951,453 | | (9,525) | - | 265,777 | 45,596,979 | - | | (11,210,747) |
| | September | 45,596,979 | 927,051 | | (9,525) | - | 272,859 | 46,787,363 | - | | (11,503,422) |
| | October | 46,787,363 | 927,051 | | (9,525) | - | 279,910 | 47,984,799 | - | | (11,797,831) |
| | November | 47,984,799 | 927,051 | | (9,525) | - | 287,004 | 49,189,328 | - | | (12,093,983) |
| | December | 49,189,328 | 927,051 | | (9,525) | - | 294,140 | 50,400,993 | - | | (12,391,891) |
| 2025 | January | 50,400,993 | | | | 1,522,393 | 230,230 | 49,108,830 | 1,522,393 | (374,304.66) | (12,074,192) |
| | February | 49,108,830 | | | | 1,522,393 | 224,415 | 47,810,853 | 1,522,393 | (374,304.66) | (11,755,063) |
| | March | 47,810,853 | | | | 1,522,393 | 218,574 | 46,507,034 | 1,522,393 | (374,304.66) | (11,434,498) |
| | April | 46,507,034 | | | | 1,522,393 | 212,707 | 45,197,348 | 1,522,393 | (374,304.66) | (11,112,491) |
| | May | 45,197,348 | | | | 1,522,393 | 206,813 | 43,881,769 | 1,522,393 | (374,304.66) | (10,789,035) |
| | June | 43,881,769 | | | | 1,522,393 | 200,893 | 42,560,269 | 1,522,393 | (374,304.66) | (10,464,123) |
| | July | 42,560,269 | | | | 1,522,393 | 194,947 | 41,232,823 | 1,522,393 | (374,304.66) | (10,137,749) |
| | August | 41,232,823 | | | | 1,522,393 | 188,973 | 39,899,403 | 1,522,393 | (374,304.66) | (9,809,907) |
| | September | 39,899,403 | | | | 1,522,393 | 182,973 | 38,559,983 | 1,522,393 | (374,304.66) | (9,480,589) |
| | October | 38,559,983 | | | | 1,522,393 | 176,945 | 37,214,535 | 1,522,393 | (374,304.66) | (9,149,789) |
| | November | 37,214,535 | | | | 1,522,393 | 170,891 | 35,863,033 | 1,522,393 | (374,304.66) | (8,817,500) |
| | December | 35,863,033 | | | | 1,522,393 | 164,809 | 34,505,449 | 1,522,393 | (374,304.66) | (8,483,717) |
| | | | **Pro Forma Amort =** | | | 18,268,715 | | | 18,268,715 | (4,491,656) | |

Note:
1. See annual revenue requirement calculation and summary of deferred O&M costs in following supporting pages.
2. Interest rate in deferral period per approved WACC per general rate case order most currently approved prior to deferral application and each subsequent annual renewal application.
3. Interest rate in amortization period per UM-1147, MBT rate, approved January 12, 2024 of 5.400%

**PacifiCorp** 
**Oregon General Rate Case - December 2025**
**Wildfire Restoration Costs Deferral Amortization**
**Revenue Requirement Summary**

| | | Wildfire Restoration Deferral - Year 1 | | |
|---|---|---|---|---|
| | | Total Company | Approved Allocation % | Oregon Allocated |
| **Revenue Requirement** | **Factor** | | | |
| Capital Investment | | | | |
| Distribution | OR | 28,514,695 | 100.000% | 28,514,695 |
| Transmission | SG | 64,453,425 | 26.053% | 16,792,052 |
| Depreciation Reserve | | | | |
| Distribution | OR | (262,121) | 100.000% | (262,121) |
| Transmission | SG | (339,692) | 26.053% | (88,500) |
| Accumulated DIT Balance | OR | (353,158) | 100.000% | (353,158) |
| Accumulated DIT Balance | SG | (773,618) | 26.053% | (201,551) |
| Net Rate Base | | 91,239,532 | | 44,401,417 |
| Pre-Tax Rate of Return | | 8.686% | | 8.686% |
| Pre-Tax Return on Rate Base | | 7,925,126 | | 3,856,737 |
| Depreciation | | | | |
| Distribution | OR | 675,561 | 100.000% | 675,561 |
| Transmission | SG | 1,086,676 | 26.053% | 283,112 |
| Deferred Income Tax Expense | SG | - | 26.053% | - |
| Annual Rev. Reqt. Before Gross-up | | 9,687,363 | | 4,815,409 |
| Monthly Rev. Reqt. Before Gross-up | | | | 401,284 |

| | | Wildfire Restoration Deferral - Year 2 | | |
|---|---|---|---|---|
| | | Total Company | Approved Allocation % | Oregon Allocated |
| **Revenue Requirement** | **Factor** | | | |
| Capital Investment | | | | |
| Distribution | OR | 63,388,334 | 100.000% | 63,388,334 |
| Transmission | SG | 151,315,884 | 26.023% | 39,376,377 |
| Depreciation Reserve | | | | |
| Distribution | OR | (1,298,581) | 100.000% | (1,298,581) |
| Transmission | SG | (2,305,066) | 26.023% | (599,839) |
| Accumulated DIT Balance | OR | (1,154,770) | 100.000% | (1,154,770) |
| Accumulated DIT Balance | SG | (2,435,478) | 26.023% | (633,775) |
| Net Rate Base | | 207,510,323 | | 99,077,745 |
| Pre-Tax Rate of Return | | 8.686% | | 8.686% |
| Pre-Tax Return on Rate Base | | 18,024,485 | | 8,605,959 |
| Depreciation | | | | |
| Distribution | OR | 1,407,836 | 100.000% | 1,407,836 |
| Transmission | SG | 2,439,370 | 26.023% | 634,788 |
| Deferred Income Tax Expense | SG | - | 26.023% | - |
| Annual Rev. Reqt. Before Gross-up | | 21,871,690 | | 10,648,583 |
| Monthly Rev. Reqt. Before Gross-up | | | | 887,382 |

**PacifiCorp** 
**Oregon General Rate Case - December 2025**
**Wildfire Restoration Costs Deferral Amortization**
**Revenue Requirement Summary**

| | | Wildfire Restoration Deferral - Year 3 | | |
|---|---|---|---|---|
| | | Total Company | Approved Allocation % | Oregon Allocated |
| **Revenue Requirement** | **Factor** | | | |
| Capital Investment | | | | |
| Distribution | OR | 75,898,180 | 100.000% | 75,898,180 |
| Transmission | SG | 142,044,704 | 26.023% | 36,963,772 |
| Depreciation Reserve | | | | |
| Distribution | OR | (2,944,747) | 100.000% | (2,944,747) |
| Transmission | SG | (4,749,635) | 26.023% | (1,235,980) |
| Accumulated DIT Balance | OR | (2,029,344) | 100.000% | (2,029,344) |
| Accumulated DIT Balance | SG | (4,146,672) | 26.023% | (1,079,073) |
| Net Rate Base | | 204,072,486 | | 105,572,807 |
| Pre-Tax Rate of Return | | 8.658% | | 8.658% |
| Pre-Tax Return on Rate Base | | 17,667,655 | | 9,140,007 |
| Depreciation | | | | |
| Distribution | OR | 1,740,739 | 100.000% | 1,740,739 |
| Transmission | SG | 2,450,744 | 26.023% | 637,748 |
| Deferred Income Tax Expense | SG | - | 26.023% | - |
| Annual Rev. Reqt. Before Gross-up | | 21,859,137 | | 11,518,494 |
| Monthly Rev. Reqt. Before Gross-up | | | | 959,874 |

| | | Wildfire Restoration Deferral - Year 4 | | |
|---|---|---|---|---|
| | | Total Company | Approved Allocation % | Oregon Allocated |
| **Revenue Requirement** | **Factor** | | | |
| Capital Investment | | | | |
| Distribution | OR | 77,680,070 | 100.000% | 77,680,070 |
| Transmission | SG | 142,848,779 | 26.002% | 37,143,198 |
| Depreciation Reserve | | | | |
| Distribution | OR | (4,713,837) | 100.000% | (4,713,837) |
| Transmission | SG | (7,208,555) | 26.002% | (1,874,351) |
| Accumulated DIT Balance | OR | (2,814,087) | 100.000% | (2,814,087) |
| Accumulated DIT Balance | SG | (5,772,073) | 26.002% | (1,500,841) |
| Net Rate Base | | 200,020,297 | | 103,920,152 |
| Pre-Tax Rate of Return | | 8.658% | | 8.658% |
| Pre-Tax Return on Rate Base | | 17,316,835 | | 8,996,927 |
| Depreciation | | | | |
| Distribution | OR | 1,779,813 | 100.000% | 1,779,813 |
| Transmission | SG | 2,464,031 | 26.002% | 640,691 |
| Deferred Income Tax Expense | SG | - | 26.002% | - |
| Annual Rev. Reqt. Before Gross-up | | 21,560,679 | | 11,417,432 |
| Monthly Rev. Reqt. Before Gross-up | | | | 951,453 |

**PacifiCorp** 
**Oregon General Rate Case - December 2025**
**Wildfire Restoration Costs Deferral Amortization**
**Revenue Requirement Summary**

| | | Wildfire Restoration Deferral - Year 5 | | |
|---|---|---|---|---|
| | | **Total Company** | **Approved Allocation %** | **Oregon Allocated** |
| **Revenue Requirement** | **Factor** | | | |
| Capital Investment | | | | |
| Distribution | OR | 77,713,756 | 100.000% | 77,713,756 |
| Transmission | SG | 142,895,852 | 26.002% | 37,155,438 |
| Depreciation Reserve | | | | |
| Distribution | OR | (6,494,125) | 100.000% | (6,494,125) |
| Transmission | SG | (9,673,183) | 26.002% | (2,515,198) |
| Accumulated DIT Balance | OR | (3,471,096) | 100.000% | (3,471,096) |
| Accumulated DIT Balance | SG | (7,150,410) | 26.002% | (1,859,233) |
| Net Rate Base | | 193,820,793 | | 100,529,542 |
| Pre-Tax Rate of Return | | 8.658% | | 8.658% |
| Pre-Tax Return on Rate Base | | 16,780,110 | | 8,703,384 |
| Depreciation | | | | |
| Distribution | OR | 1,780,351 | 100.000% | 1,780,351 |
| Transmission | SG | 2,464,726 | 26.002% | 640,872 |
| Deferred Income Tax Expense | SG | - | 26.002% | - |
| Annual Rev. Reqt. Before Gross-up | | 21,025,187 | | 11,124,607 |
| Monthly Rev. Reqt. Before Gross-up | | | | 927,051 |

**PacifiCorp** 
**Oregon General Rate Case - December 2025**
**Wildfire Restoration Costs Deferral Amortization**
**Restoration Capital Cost Details**

**Deferal Year 1**

| | Gross Plant In Service | | Accumulated Depreciation | | | Depreciation Expense | |
|---|---|---|---|---|---|---|---|
| | Distribution | Transmission | Distribution | Transmission | | Distribution | Transmission |
| Aug-20 | - | - | - | - | Aug-20 | - | - |
| Sep-20 | 2,776,913 | - | (2,925) | - | Sep-20 | 2,925 | - |
| Oct-20 | 4,565,309 | 68,219 | (10,660) | (50) | Oct-20 | 7,734 | 50 |
| Nov-20 | 14,424,732 | 74,050 | (30,664) | (153) | Nov-20 | 20,005 | 104 |
| Dec-20 | 36,099,056 | 70,263,275 | (83,887) | (51,440) | Dec-20 | 53,223 | 51,286 |
| Jan-21 | 37,286,876 | 69,324,408 | (153,937) | (151,759) | Jan-21 | 70,050 | 100,319 |
| Feb-21 | 37,564,721 | 69,524,073 | (225,386) | (251,547) | Feb-21 | 71,449 | 99,788 |
| Mar-21 | 37,974,366 | 69,638,672 | (297,492) | (351,561) | Mar-21 | 72,105 | 100,014 |
| Apr-21 | 38,067,509 | 70,032,834 | (370,077) | (451,941) | Apr-21 | 72,585 | 100,380 |
| May-21 | 38,173,064 | 70,235,868 | (442,852) | (552,749) | May-21 | 72,775 | 100,809 |
| Jun-21 | 40,549,906 | 89,852,182 | (517,997) | (667,802) | Jun-21 | 75,145 | 115,053 |
| Jul-21 | 41,308,375 | 164,101,331 | (596,134) | (850,314) | Jul-21 | 78,137 | 182,512 |
| Aug-21 | 41,900,208 | 164,779,611 | (675,561) | (1,086,676) | Aug-21 | 79,426 | 236,361 |
| **13-mo average** | **28,514,695** | **64,453,425** | **(262,121)** | **(339,692)** | **12-mo ending** | **675,561** | **1,086,676** |

**Deferal Year 2**

| | Gross Plant In Service | | Accumulated Depreciation | | | Depreciation Expense | |
|---|---|---|---|---|---|---|---|
| Wind Generation | Distribution | Transmission | Distribution | Transmission | | Distribution | Transmission |
| Aug-21 | 41,900,208 | 164,779,611 | (675,561) | (1,086,676) | Aug-21 | 79,426 | 236,361 |
| Sep-21 | 43,705,576 | 165,213,393 | (757,275) | (1,323,836) | Sep-21 | 81,715 | 237,161 |
| Oct-21 | 44,796,266 | 186,889,738 | (785,435) | (1,408,186) | Oct-21 | 28,160 | 84,350 |
| Nov-21 | 45,884,548 | 186,929,980 | (871,994) | (1,676,845) | Nov-21 | 86,559 | 268,658 |
| Dec-21 | 71,038,012 | 140,329,131 | (983,602) | (1,912,040) | Dec-21 | 111,608 | 235,196 |
| Jan-22 | 71,520,557 | 140,341,619 | (1,119,681) | (2,113,754) | Jan-22 | 136,079 | 201,713 |
| Feb-22 | 71,756,491 | 140,341,705 | (1,256,445) | (2,315,476) | Feb-22 | 136,764 | 201,723 |
| Mar-22 | 72,225,328 | 140,315,904 | (1,393,882) | (2,517,180) | Mar-22 | 137,437 | 201,704 |
| Apr-22 | 72,181,457 | 140,315,904 | (1,531,725) | (2,718,866) | Apr-22 | 137,843 | 201,685 |
| May-22 | 72,273,430 | 140,315,904 | (1,669,614) | (2,920,551) | May-22 | 137,889 | 201,685 |
| Jun-22 | 72,213,181 | 140,376,558 | (1,807,533) | (3,122,280) | Jun-22 | 137,919 | 201,729 |
| Jul-22 | 72,233,859 | 140,478,525 | (1,945,414) | (3,324,126) | Jul-22 | 137,881 | 201,846 |
| Aug-22 | 72,319,433 | 140,478,525 | (2,083,397) | (3,526,046) | Aug-22 | 137,983 | 201,919 |
| **13-mo average** | **63,388,334** | **151,315,884** | **(1,298,581)** | **(2,305,066)** | **12-mo ending** | **1,407,836** | **2,439,370** |

| | | |
|---|---|---|
| *Depreciation Rate* | *2.528%* | *1.750%* |
| *Depreciation Rate* | *2.291%* | *1.725%* |

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Wildfire Restoration Costs Deferral Amortization**
**Restoration Capital Cost Details**



**Deferral Year 3**

| | Gross Plant In Service | | Accumulated Depreciation | | | Depreciation Expense | |
|---|---|---|---|---|---|---|---|
| | Distribution | Transmission | Distribution | Transmission | | Distribution | Transmission |
| Aug-22 | 72,319,433 | 140,478,525 | (2,083,397) | (3,526,046) | Aug-22 | 137,983 | 201,919 |
| Sep-22 | 72,345,071 | 140,478,525 | (2,221,485) | (3,727,965) | Sep-22 | 138,089 | 201,919 |
| Oct-22 | 73,861,156 | 142,471,166 | (2,361,046) | (3,931,316) | Oct-22 | 139,560 | 203,351 |
| Nov-22 | 75,055,967 | 142,843,950 | (2,503,194) | (4,136,367) | Nov-22 | 142,148 | 205,051 |
| Dec-22 | 76,389,613 | 141,839,497 | (2,647,756) | (4,340,965) | Dec-22 | 144,562 | 204,597 |
| Jan-23 | 76,658,296 | 141,928,351 | (2,793,847) | (4,544,904) | Jan-23 | 146,091 | 203,939 |
| Feb-23 | 76,678,259 | 142,021,033 | (2,940,214) | (4,748,974) | Feb-23 | 146,367 | 204,070 |
| Mar-23 | 76,781,055 | 142,103,478 | (3,086,697) | (4,953,169) | Mar-23 | 146,484 | 204,196 |
| Apr-23 | 77,201,056 | 142,399,767 | (3,233,680) | (5,157,637) | Apr-23 | 146,983 | 204,468 |
| May-23 | 77,273,392 | 142,366,857 | (3,381,133) | (5,362,294) | May-23 | 147,453 | 204,657 |
| Jun-23 | 77,343,830 | 142,466,854 | (3,528,722) | (5,567,000) | Jun-23 | 147,589 | 204,705 |
| Jul-23 | 77,367,947 | 142,544,664 | (3,676,402) | (5,771,833) | Jul-23 | 147,679 | 204,833 |
| Aug-23 | 77,401,262 | 142,638,492 | (3,824,136) | (5,976,789) | Aug-23 | 147,734 | 204,956 |
| **13-mo average** | **75,898,180** | **142,044,704** | **(2,944,747)** | **(4,749,635)** | **12-mo ending** | **1,740,739** | **2,450,744** |

**Deferral Year 4**

| | Gross Plant In Service | | Accumulated Depreciation | | | Depreciation Expense | |
|---|---|---|---|---|---|---|---|
| Wind Generation | Distribution | Transmission | Distribution | Transmission | | Distribution | Transmission |
| Aug-23 | 77,401,262 | 142,638,492 | (3,824,136) | (5,976,789) | Aug-23 | 147,734 | 204,956 |
| Sep-23 | 77,650,166 | 142,716,843 | (3,972,140) | (6,181,869) | Sep-23 | 148,004 | 205,080 |
| Oct-23 | 77,677,534 | 142,765,790 | (4,120,407) | (6,387,041) | Oct-23 | 148,267 | 205,172 |
| Nov-23 | 77,688,143 | 142,850,331 | (4,268,710) | (6,592,309) | Nov-23 | 148,304 | 205,268 |
| Dec-23 | 77,713,756 | 142,895,852 | (4,417,049) | (6,797,670) | Dec-23 | 148,338 | 205,361 |
| Jan-24 | 77,713,756 | 142,895,852 | (4,565,411) | (7,003,064) | Jan-24 | 148,363 | 205,394 |
| Feb-24 | 77,713,756 | 142,895,852 | (4,713,774) | (7,208,457) | Feb-24 | 148,363 | 205,394 |
| Mar-24 | 77,713,756 | 142,895,852 | (4,862,136) | (7,413,851) | Mar-24 | 148,363 | 205,394 |
| Apr-24 | 77,713,756 | 142,895,852 | (5,010,499) | (7,619,245) | Apr-24 | 148,363 | 205,394 |
| May-24 | 77,713,756 | 142,895,852 | (5,158,862) | (7,824,639) | May-24 | 148,363 | 205,394 |
| Jun-24 | 77,713,756 | 142,895,852 | (5,307,224) | (8,030,033) | Jun-24 | 148,363 | 205,394 |
| Jul-24 | 77,713,756 | 142,895,852 | (5,455,587) | (8,235,426) | Jul-24 | 148,363 | 205,394 |
| Aug-24 | 77,713,756 | 142,895,852 | (5,603,949) | (8,440,820) | Aug-24 | 148,363 | 205,394 |
| **13-mo average** | **77,680,070** | **142,848,779** | **(4,713,837)** | **(7,208,555)** | **12-mo ending** | **1,779,813** | **2,464,031** |
| | | | | | *Depreciation Rate* | *2.291%* | *1.725%* |

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Wildfire Restoration Costs Deferral Amortization**
**Restoration Capital Cost Details**



**Deferral Year 5**

| | Gross Plant In Service | | Accumulated Depreciation | | | Depreciation Expense | |
|---|---|---|---|---|---|---|---|
| | Distribution | Transmission | Distribution | Transmission | | Distribution | Transmission |
| Aug-24 | 77,713,756 | 142,895,852 | (5,603,949) | (8,440,820) | Aug-24 | 148,363 | 205,394 |
| Sep-24 | 77,713,756 | 142,895,852 | (5,752,312) | (8,646,214) | Sep-24 | 148,363 | 205,394 |
| Oct-24 | 77,713,756 | 142,895,852 | (5,900,675) | (8,851,608) | Oct-24 | 148,363 | 205,394 |
| Nov-24 | 77,713,756 | 142,895,852 | (6,049,037) | (9,057,002) | Nov-24 | 148,363 | 205,394 |
| Dec-24 | 77,713,756 | 142,895,852 | (6,197,400) | (9,262,396) | Dec-24 | 148,363 | 205,394 |
| Jan-25 | 77,713,756 | 142,895,852 | (6,345,762) | (9,467,789) | Jan-25 | 148,363 | 205,394 |
| Feb-25 | 77,713,756 | 142,895,852 | (6,494,125) | (9,673,183) | Feb-25 | 148,363 | 205,394 |
| Mar-25 | 77,713,756 | 142,895,852 | (6,642,488) | (9,878,577) | Mar-25 | 148,363 | 205,394 |
| Apr-25 | 77,713,756 | 142,895,852 | (6,790,850) | (10,083,971) | Apr-25 | 148,363 | 205,394 |
| May-25 | 77,713,756 | 142,895,852 | (6,939,213) | (10,289,365) | May-25 | 148,363 | 205,394 |
| Jun-25 | 77,713,756 | 142,895,852 | (7,087,575) | (10,494,758) | Jun-25 | 148,363 | 205,394 |
| Jul-25 | 77,713,756 | 142,895,852 | (7,235,938) | (10,700,152) | Jul-25 | 148,363 | 205,394 |
| Aug-25 | 77,713,756 | 142,895,852 | (7,384,301) | (10,905,546) | Aug-25 | 148,363 | 205,394 |
| **13-mo average** | **77,713,756** | **142,895,852** | **(6,494,125)** | **(9,673,183)** | **12-mo ending** | **1,780,351** | **2,464,726** |
| | | | | | *Depreciation Rate* | *2.291%* | *1.725%* |

**PacifiCorp** 
**Oregon General Rate Case - December 2025**
**Wildfire Restoration Costs Deferral Amortization**
**Restoration Capital Cost Details**
**Tax Balances Summary**

**Deferral Year 1**

| | Distribution ADIT | Transmission ADIT | Total ADIT |
|---|---|---|---|
| Aug-20 | (12,802) | 0 | (12,802) |
| Sep-20 | (18,484) | 0 | (18,484) |
| Oct-20 | (121,126) | (215,930) | (337,056) |
| Nov-20 | (220,751) | (431,846) | (652,597) |
| Dec-20 | (312,209) | (635,178) | (947,387) |
| Jan-21 | (349,821) | (713,959) | (1,063,780) |
| Feb-21 | (387,089) | (792,871) | (1,179,960) |
| Mar-21 | (424,196) | (871,727) | (1,295,923) |
| Apr-21 | (465,143) | (981,555) | (1,446,698) |
| May-21 | (506,043) | (1,091,277) | (1,597,320) |
| Jun-21 | (546,360) | (1,197,497) | (1,743,857) |
| Jul-21 | (591,236) | (1,445,307) | (2,036,543) |
| Aug-21 | (635,796) | (1,679,878) | (2,315,674) |
| **13-mo average** | **(353,158)** | **(773,618)** | **(1,126,775)** |

**Deferral Year 2**

| | Distribution ADIT | Transmission ADIT | Total ADIT |
|---|---|---|---|
| Aug-21 | (635,796) | (1,679,878) | (2,315,674) |
| Sep-21 | (679,793) | (1,914,252) | (2,594,045) |
| Oct-21 | (816,109) | (1,993,915) | (2,810,024) |
| Nov-21 | (938,067) | (2,028,263) | (2,966,330) |
| Dec-21 | (1,053,866) | (2,070,838) | (3,124,704) |
| Jan-22 | (1,122,384) | (2,220,990) | (3,343,374) |
| Feb-22 | (1,190,733) | (2,371,139) | (3,561,872) |
| Mar-22 | (1,258,917) | (2,521,293) | (3,780,210) |
| Apr-22 | (1,326,983) | (2,671,545) | (3,998,528) |
| May-22 | (1,395,037) | (2,821,797) | (4,216,834) |
| Jun-22 | (1,463,084) | (2,972,038) | (4,435,122) |
| Jul-22 | (1,531,453) | (3,122,439) | (4,653,892) |
| Aug-22 | (1,599,798) | (3,272,822) | (4,872,620) |
| **13-mo average** | **(1,154,770)** | **(2,435,478)** | **(3,590,248)** |

**PacifiCorp** Page 8.18.10_R
**Oregon General Rate Case - December 2025**
**Wildfire Restoration Costs Deferral Amortization**
**Restoration Capital Cost Details**
**Tax Balances Summary**

**Deferral Year 3**

| | Distribution ADIT | Transmission ADIT | Total ADIT |
|---|---|---|---|
| Aug-22 | (1,599,798) | (3,272,822) | (4,872,620) |
| Sep-22 | (1,668,116) | (3,423,205) | (5,091,321) |
| Oct-22 | (1,748,300) | (3,577,262) | (5,325,562) |
| Nov-22 | (1,827,848) | (3,730,901) | (5,558,749) |
| Dec-22 | (1,906,802) | (3,884,652) | (5,791,453) |
| Jan-23 | (1,972,585) | (4,021,725) | (5,994,309) |
| Feb-23 | (2,038,300) | (4,158,766) | (6,197,065) |
| Mar-23 | (2,103,986) | (4,295,776) | (6,399,761) |
| Apr-23 | (2,170,414) | (4,433,278) | (6,603,691) |
| May-23 | (2,236,727) | (4,570,733) | (6,807,459) |
| Jun-23 | (2,303,006) | (4,708,176) | (7,011,181) |
| Jul-23 | (2,369,537) | (4,845,885) | (7,215,421) |
| Aug-23 | (2,436,054) | (4,983,563) | (7,419,616) |
| **13-mo average** | **(2,029,344)** | **(4,146,672)** | **(6,176,016)** |

**Deferral Year 4**

| | Distribution ADIT | Transmission ADIT | Total ADIT |
|---|---|---|---|
| Aug-23 | (2,436,054) | (4,983,563) | (7,419,616) |
| Sep-23 | (2,502,505) | (5,121,211) | (7,623,715) |
| Oct-23 | (2,568,616) | (5,259,003) | (7,827,618) |
| Nov-23 | (2,634,718) | (5,396,771) | (8,031,488) |
| Dec-23 | (2,700,811) | (5,534,515) | (8,235,326) |
| Jan-24 | (2,760,087) | (5,658,564) | (8,418,651) |
| Feb-24 | (2,819,363) | (5,782,613) | (8,601,976) |
| Mar-24 | (2,878,639) | (5,906,662) | (8,785,301) |
| Apr-24 | (2,937,915) | (6,030,711) | (8,968,626) |
| May-24 | (2,997,191) | (6,154,760) | (9,151,951) |
| Jun-24 | (3,056,467) | (6,278,809) | (9,335,276) |
| Jul-24 | (3,115,743) | (6,402,858) | (9,518,601) |
| Aug-24 | (3,175,019) | (6,526,907) | (9,701,926) |
| **13-mo average** | **(2,814,087)** | **(5,772,073)** | **(8,586,159)** |

**PacifiCorp** 
**Oregon General Rate Case - December 2025**
**Wildfire Restoration Costs Deferral Amortization**
**Restoration Capital Cost Details**
**Tax Balances Summary**

**Deferral Year 5**

| | Distribution ADIT | Transmission ADIT | Total ADIT |
|---|---|---|---|
| Aug-24 | (3,175,019) | (6,526,907) | (9,701,926) |
| Sep-24 | (3,234,295) | (6,650,957) | (9,885,251) |
| Oct-24 | (3,293,571) | (6,775,006) | (10,068,577) |
| Nov-24 | (3,352,846) | (6,899,055) | (10,251,902) |
| Dec-24 | (3,412,122) | (7,023,105) | (10,435,227) |
| Jan-25 | (3,459,791) | (7,124,636) | (10,584,427) |
| Feb-25 | (3,503,464) | (7,217,656) | (10,721,120) |
| Mar-25 | (3,542,712) | (7,301,252) | (10,843,964) |
| Apr-25 | (3,577,679) | (7,375,729) | (10,953,408) |
| May-25 | (3,608,221) | (7,440,782) | (11,049,003) |
| Jun-25 | (3,634,482) | (7,496,715) | (11,131,197) |
| Jul-25 | (3,656,318) | (7,543,225) | (11,199,543) |
| Aug-25 | (3,673,730) | (7,580,311) | (11,254,041) |
| **13-mo average** | **(3,471,096)** | **(7,150,410)** | **(10,621,507)** |

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Wildfire Restoration Costs Deferral Amortization**
**Restoration O&M Costs Summary**



| | Distribution - OREGON | | | | | | |
|---|---|---|---|---|---|---|---|
| | Almeda Fire Damage Repair | Archie Creek Fire Damage Repair | Beachie Creek Fire Damage Repair | Echo Mountain Fire Damage Repair | Slater Fire (Happy Camp) Fire Damage | Two Four Two Fire Damage Repair | Total |
| Sep-20 | 315,376 | 189,081 | 316,260 | 163,751 | 116,792 | 65,876 | 1,167,136 |
| Oct-20 | 21,828 | (70,315) | 62,436 | 130,898 | (38,582) | 35,508 | 141,774 |
| Nov-20 | (60,220) | 200,443 | (48,242) | (62,854) | 70,302 | (55,867) | 43,562 |
| Dec-20 | 33,977 | 415,012 | (86,079) | 92,698 | (5,713) | 162,402 | 612,297 |
| Jan-21 | 35,018 | 11,303 | 5,041 | 2,719 | - | 29,086 | 83,167 |
| Feb-21 | 100 | 9,973 | 300 | 710 | 26 | - | 11,109 |
| Mar-21 | (33,085) | (354) | (1,340) | (368) | - | - | (35,148) |
| Apr-21 | 2,482 | 5,111 | (253) | 13 | - | - | 7,353 |
| May-21 | 1,595 | 328 | - | 31,322 | - | - | 33,244 |
| Jun-21 | - | 3,065 | - | - | - | - | 3,065 |
| Jul-21 | - | 147 | - | - | - | - | 147 |
| Aug-21 | - | - | - | - | - | - | - |
| Sep-21 | - | 115 | - | - | - | - | 115 |
| Oct-21 | - | 1,437 | - | - | - | - | 1,437 |
| Nov-21 | - | - | 575 | - | - | - | 575 |
| Dec-21 | - | (900) | - | - | - | - | (900) |
| Jan-22 | - | - | - | - | - | - | - |
| Feb-22 | - | - | - | - | - | - | - |
| Mar-22 | - | 268 | 1,925 | - | - | - | 2,193 |
| Apr-22 | - | - | (600) | - | - | - | (600) |
| May-22 | - | - | - | - | - | - | - |
| Jun-22 | - | - | 823 | - | - | - | 823 |
| | 317,071 | 764,715 | 250,846 | 358,890 | 142,826 | 237,004 | **2,071,352** |

| | Transmission - System | | | | | | |
|---|---|---|---|---|---|---|---|
| | Archie Creek Fire Damage Repair | Slater Fire (Happy Camp) Fire Damage | Echo Mountain Fire Damage Repair | Two Four Two Fire Damage Repair | Total | SG Allocation | Oregon Allocated Total |
| Sep-20 | 154,261 | - | 94,435 | 18,772 | 267,469 | 26.053% | 69,684 |
| Oct-20 | 96,846 | - | (51,157) | 19,259 | 64,948 | 26.053% | 16,921 |
| Nov-20 | 209,247 | 32,653 | 5,400 | (2,150) | 245,149 | 26.053% | 63,869 |
| Dec-20 | (70,108) | 185,318 | 76,987 | (31,717) | 160,480 | 26.053% | 41,810 |
| Jan-21 | - | - | 33,075 | 29,086 | 62,161 | 26.023% | 16,176 |
| Feb-21 | 285 | - | - | - | 285 | 26.023% | 74 |
| Mar-21 | 951 | - | - | - | 951 | 26.023% | 248 |
| Apr-21 | - | - | - | - | - | 26.023% | - |
| May-21 | - | - | - | - | - | 26.023% | - |
| Jun-21 | - | - | - | - | - | 26.023% | - |
| Jul-21 | - | - | - | - | - | 26.023% | - |
| Aug-21 | - | - | - | - | - | 26.023% | - |
| Sep-21 | - | - | - | - | - | 26.023% | - |
| Oct-21 | - | - | - | - | - | 26.023% | - |
| Nov-21 | - | - | - | - | - | 26.023% | - |
| Dec-21 | - | - | - | - | - | 26.023% | - |
| Jan-22 | 1,088 | - | - | - | 1,088 | 26.023% | 283 |
| Feb-22 | 1,526 | - | - | - | 1,526 | 26.023% | 397 |
| Mar-22 | - | - | - | - | - | 26.023% | - |
| Apr-22 | 89 | - | - | - | 89 | 26.023% | 23 |
| May-22 | 32,643 | - | - | - | 32,643 | 26.023% | 8,495 |
| Jun-22 | 20,063 | - | - | - | 20,063 | 26.023% | 5,221 |
| Jul-22 | 2,018 | - | - | - | 2,018 | 26.023% | 525 |
| Aug-22 | 9,183 | - | - | - | 9,183 | 26.023% | 2,390 |
| Sep-22 | (50) | - | - | - | (50) | 26.023% | (13) |
| Oct-22 | 3,727 | - | - | - | 3,727 | 26.023% | 970 |
| Nov-22 | (7,340) | - | - | - | (7,340) | 26.023% | (1,910) |
| Dec-22 | - | - | - | - | - | 26.023% | - |
| Jan-23 | 223 | - | - | - | 223 | 26.002% | 58 |
| Feb-23 | 268 | - | - | - | 268 | 26.002% | 70 |
| | 454,919 | 217,970 | 158,740 | 33,250 | 864,880 | | **225,289** |

**Total O&M Deferred** **2,296,641**

**PacifiCorp** Page 8.18.14_R
**Oregon General Rate Case - December 2025**
**Wildfire Restoration Costs Deferral Amortization**
**Revenue Requirement Summary**

| | | Damaged Plant Removal - UE-263 | | |
|---|---|---|---|---|
| | | Total Company | Approved Allocation % | Oregon Allocated |
| **Revenue Requirement** | **Factor** | | | |
| Capital Investment | | | | |
| Distribution | OR | 1,681,235 | 100.000% | 1,681,235 |
| Transmission | SG | 528,774 | 26.053% | 137,762 |
| Depreciation Reserve | | | | |
| Distribution | OR | (978,844) | 100.000% | (978,844) |
| Transmission | SG | (176,779) | 26.053% | (46,056) |
| Accumulated DIT Balance | OR | (101,759) | 100.000% | (101,759) |
| Accumulated DIT Balance | SG | (63,175) | 26.053% | (16,459) |
| Net Rate Base | | 889,452 | | 675,878 |
| Pre-Tax Rate of Return | | 8.686% | | 8.686% |
| Pre-Tax Return on Rate Base | | 77,258 | | 58,707 |
| Depreciation | | | | |
| Distribution | OR | 42,505 | 100.000% | 42,505 |
| Transmission | SG | 9,253 | 26.053% | 2,411 |
| Deferred Income Tax Expense | SG | - | 26.053% | - |
| Annual Rev. Reqt. Before Gross-up | | 129,017 | | 103,623 |
| Monthly Rev. Reqt. Before Gross-up | | | | 8,635 |

| | | Damaged Plant Removal - UE-374 | | |
|---|---|---|---|---|
| | | Total Company | Approved Allocation % | Oregon Allocated |
| **Revenue Requirement** | **Factor** | | | |
| Capital Investment | | | | |
| Distribution | OR | 2,596,087 | 100.000% | 2,596,087 |
| Transmission | SG | 852,907 | 26.023% | 221,949 |
| Depreciation Reserve | | | | |
| Distribution | OR | (1,182,003) | 100.000% | (1,182,003) |
| Transmission | SG | (282,927) | 26.023% | (73,625) |
| Accumulated DIT Balance | OR | (85,145) | 100.000% | (85,145) |
| Accumulated DIT Balance | SG | (81,590) | 26.023% | (21,232) |
| Net Rate Base | | 1,817,330 | | 1,456,031 |
| Pre-Tax Rate of Return | | 8.686% | | 8.686% |
| Pre-Tax Return on Rate Base | | 157,854 | | 126,472 |
| Depreciation | | | | |
| Distribution | OR | 59,474 | 100.000% | 59,474 |
| Transmission | SG | 14,711 | 26.023% | 3,828 |
| Deferred Income Tax Expense | SG | - | 26.023% | - |
| Annual Rev. Reqt. Before Gross-up | | 232,040 | | 189,774 |
| Monthly Rev. Reqt. Before Gross-up | | | | 15,815 |

**PacifiCorp**



**Oregon General Rate Case - December 2025**
**Wildfire Restoration Costs Deferral Amortization**
**Revenue Requirement Summary**

| | | Damaged Plant Removal - UE-399 | | |
|---|---|---|---|---|
| | | Total Company | Approved Allocation % | Oregon Allocated |
| **Revenue Requirement** | **Factor** | | | |
| Capital Investment | | | | |
| Distribution | OR | 1,370,550 | 100.000% | 1,370,550 |
| Transmission | SG | 568,171 | 26.023% | 147,853 |
| Depreciation Reserve | | | | |
| Distribution | OR | (456,676) | 100.000% | (456,676) |
| Transmission | SG | (191,957) | 26.023% | (49,952) |
| Accumulated DIT Balance | OR | (67,758) | 100.000% | (67,758) |
| Accumulated DIT Balance | SG | (61,059) | 26.023% | (15,889) |
| Net Rate Base | | 1,161,272 | | 928,129 |
| Pre-Tax Rate of Return | | 8.658% | | 8.658% |
| Pre-Tax Return on Rate Base | | 100,538 | | 80,353 |
| Depreciation | | | | |
| Distribution | OR | 31,398 | 100.000% | 31,398 |
| Transmission | SG | 9,800 | 26.023% | 2,550 |
| Deferred Income Tax Expense | SG | - | 26.023% | - |
| Annual Rev. Reqt. Before Gross-up | | 141,736 | | 114,301 |
| Monthly Rev. Reqt. Before Gross-up | | | | 9,525 |

# Tab R - Reply Adjustments

**PacifiCorp** 

**Oregon General Rate Case – December 2025**

**Reply Adjustment Index**

The following adjustments were incorporated into the Company's Reply revenue requirement. For further details, please see the Reply Testimony of Ms. Sherona L. Cheung.

R_1 Capitalization of Officer Incentives
R_2 Remove Customer Service Project

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Reply Adjustment Summary**

| | | | R_1 | R_2 |
|---|---|---|---|---|
| | | Total Adjustments | Capitalization of Officer Incentives | Remove Customer Service Project |
| 1 | Operating Revenues: | | | |
| 2 | General Business Revenues | - | - | - |
| 3 | Interdepartmental | - | - | - |
| 4 | Special Sales | - | - | - |
| 5 | Other Operating Revenues | - | - | - |
| 6 | Total Operating Revenues | - | - | - |
| 7 | | | | |
| 8 | Operating Expenses: | | | |
| 9 | Steam Production | - | - | - |
| 10 | Nuclear Production | - | - | - |
| 11 | Hydro Production | - | - | - |
| 12 | Other Power Supply | - | - | - |
| 13 | Transmission | - | - | - |
| 14 | Distribution | - | - | - |
| 15 | Customer Accounting | - | - | - |
| 16 | Customer Service & Info | - | - | - |
| 17 | Sales | - | - | - |
| 18 | Administrative & General | - | - | - |
| 19 | | | | |
| 20 | Total O&M Expenses | - | - | - |
| 21 | | | | |
| 22 | Depreciation | (2,916) | (2,916) | - |
| 23 | Amortization | (3,093,223) | - | (3,093,223) |
| 24 | Taxes Other Than Income | - | - | - |
| 25 | Income Taxes - Federal | 3,953,006 | 1,562 | 3,951,444 |
| 26 | Income Taxes - State | 895,246 | 354 | 894,893 |
| 27 | Income Taxes - Def Net | (3,878,445) | (725) | (3,877,720) |
| 28 | Investment Tax Credit Adj. | - | - | - |
| 29 | Misc Revenue & Expense | - | - | - |
| 30 | | | | |
| 31 | Total Operating Expenses: | (2,126,331) | (1,725) | (2,124,606) |
| 32 | | | | |
| 33 | Operating Rev For Return: | 2,126,331 | 1,725 | 2,124,606 |
| 34 | | | | |
| 35 | Rate Base: | | | |
| 36 | Electric Plant In Service | (42,440,727) | - | (42,440,727) |
| 37 | Plant Held for Future Use | - | - | - |
| 38 | Misc Deferred Debits | - | - | - |
| 39 | Elec Plant Acq Adj | - | - | - |
| 40 | Nuclear Fuel | - | - | - |
| 41 | Prepayments | - | - | - |
| 42 | Fuel Stock | - | - | - |
| 43 | Material & Supplies | - | - | - |
| 44 | Working Capital | 147,102 | 58 | 147,043 |
| 45 | Weatherization Loans | - | - | - |
| 46 | Misc Rate Base | (98,566) | (98,566) | - |
| 47 | | | | |
| 48 | Total Electric Plant: | (42,392,192) | (98,508) | (42,293,684) |
| 49 | | | | |
| 50 | Rate Base Deductions: | | | |
| 51 | Accum Prov For Deprec | - | - | - |
| 52 | Accum Prov For Amort | 3,093,223 | - | 3,093,223 |
| 53 | Accum Def Income Tax | 7,158,032 | 24,234 | 7,133,798 |
| 54 | Unamortized ITC | - | - | - |
| 55 | Customer Adv For Const | - | - | - |
| 56 | Customer Service Deposits | - | - | - |
| 57 | Misc Rate Base Deductions | - | - | - |
| 58 | | | | |
| 59 | Total Rate Base Deductions | 10,251,255 | 24,234 | 10,227,021 |
| 60 | | | | |
| 61 | Total Rate Base: | (32,140,936) | (74,274) | (32,066,663) |
| 62 | | | | |
| 63 | Return on Rate Base | 0.077% | 0.000% | 0.076% |
| 64 | | | | |
| 65 | Return on Equity | 0.153% | 0.000% | 0.153% |
| 66 | | | | |
| 67 | TAX CALCULATION: | | | |
| 68 | Operating Revenue | 3,096,139 | 2,916 | 3,093,223 |
| 69 | Other Deductions | | - | - |
| 70 | Interest (AFUDC) | - | - | - |
| 71 | Interest | (848,351) | (1,960) | (846,391) |
| 72 | Schedule "M" Additions | (3,093,223) | - | (3,093,223) |
| 73 | Schedule "M" Deductions | (18,867,819) | (2,916) | (18,864,903) |
| 74 | Income Before Tax | 19,719,086 | 7,792 | 19,711,294 |
| 75 | | | | |
| 76 | State Income Taxes | 895,246 | 354 | 894,893 |
| 77 | Taxable Income | 18,823,839 | 7,438 | 18,816,401 |
| 78 | | | | |
| 79 | Federal Income Taxes + Other | 3,953,006 | 1,562 | 3,951,444 |
| | APPROXIMATE PRICE CHANGE | (6,216,703) | (9,986) | (6,206,717) |

**PacifiCorp** PAGE R_1
**Oregon General Rate Case - December 2025**
**Capitalization of Officer Incentives**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Depreciation Expense:** | | | | | | | |
| Deprec. Exp. Capitalization of Officer Incentive | 403368 | 3 | (2,916) | OR | Situs | (2,916) | R_1.1 |
| **Adjustment to Rate Base:** | | | | | | | |
| Remove Capitalization of Officer Incentive | 1869 | 3 | (98,566) | OR | Situs | (98,566) | R_1.1 |
| **Adjustment to Tax:** | | | | | | | |
| Schedule M Adjustment | SCHMDT | 3 | (2,916) | OR | Situs | (2,916) | |
| Deferred Income Tax Expense | 41010 | 3 | (725) | OR | Situs | (725) | |
| ADIT Balance | 282 | 3 | 24,234 | OR | Situs | 24,234 | |

**Description of Adjustment:**

This adjustment includes a reduction to rate base and associated depreciation expense regarding officer incentives prepared in a consistent manner with the adjustment approved in Commission order in Docket No. UE-374 and again adopted through Commission order in Docket No. UE-399. The Company's last general rate case (UE-399) was effective 2023. The current general rate case is requested to be effective 2025. Accordingly, the Company has calculated the capitalized incentives since the last case (2023), and prepared this adjustment to remove 2024's capitalized incentives. However, since 2024 balance is yet unknown, for purposes of this adjustment the Company applied OPUC Staff's five-year average methodology used in the prior rate case to estimate for years for which data was not yet available.

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Capitalization and Depreciation Expense of Officer Incentives**



**Removal of Capitalization of Officer Incentives**

| Calendar Year | PacifiCorp NEO Capitalized AIP | Oregon's Allocated share | Source |
|---|---|---|---|
| 2019 | 371,909 | 102,434 | OPUC 481 |
| 2020 | 430,706 | 121,213 | OPUC 481 |
| 2021 | 330,571 | 92,533 | OPUC 481 |
| 2022 | 388,131 | 107,783 | OPUC 481 |
| 2023 | 246,289 | 68,867 | OPUC 481 |
| 2024 | 353,521 | 98,566 | 5-Yr Historical Ave (2019 - 2023) |
| Removal: | | | |
| 2024 | 353,521 | 98,566 | Percentage |
| | **353,521** | **98,566** | 27.881% |
| | | **Ref. R_1** | |

**Depreciation Expense of Officer Incentives**

| | |
|---|---|
| Test Year Gross Plant | 10,718,454,229 |
| Annual Test Year Depreciation | 317,077,683 |
| Average Depreciation Percentage to Rate Base | 2.96% |
| | (Oregon Share) |
| | **2,916** |
| | **Ref. R_1** |

**PacifiCorp** PAGE R_2
**Oregon General Rate Case - December 2025**
**Remove Customer Service Project**

| | ACCOUNT | Type | TOTAL COMPANY | FACTOR | FACTOR % | OREGON ALLOCATED | REF# |
|---|---|---|---|---|---|---|---|
| **Adjustment to Rate Base:** | | | | | | | |
| Remove Pro Forma Capital | 303 | 3 | (154,749,340) | SO | 27.425% | (42,440,727) | R_2.1 |
| **Adjustment to Depreciation Expense:** | | | | | | | |
| Remove Pro Forma Depreciation Expense | 404IP | 3 | (11,278,654) | SO | 27.425% | (3,093,223) | R_2.1 |
| **Adjustment to Depreciation Reserve:** | | | | | | | |
| Remove Pro Forma Depreciation Reserve | 111IP | 3 | 11,278,654 | SO | 27.425% | 3,093,223 | R_2.1 |
| **Adjustment to Tax:** | | | | | | | |
| Schedule M Addition - SO - 2025 Book Depr | SCHMAT | 3 | (11,278,654) | SO | 27.425% | (3,093,223) | |
| Schedule M Deduction - SO - 2025 Tax Depr | SCHMDT | 3 | (68,786,081) | SO | 27.425% | (18,864,903) | |
| Deferred Inc Tax Exp - SO - 2025 Book Depr | 41110 | 3 | 2,773,037 | SO | 27.425% | 760,518 | |
| Deferred Inc Tax Exp - SO - 2025 Book Depr | 41010 | 3 | (16,912,159) | SO | 27.425% | (4,638,238) | |
| Deferred Inc Tax Exp - SO - 2025 Book Depr | 282 | 3 | 26,011,583 | SO | 27.425% | 7,133,798 | |

**Description of Adjustment:**

This adjustment removes from test period results the Oracle Systems-Customer project impacts that were included in adjustments 8.5, 6.1, 6.2 and 7.6 in the Company's direct filing in Exhibit PAC/1702.

**PacifiCorp**
**Oregon General Rate Case - December 2025**
**Remove Customer Service Project**

**Electric Plant in Service**

| | Account | Factor | Dec-23 | Jan-24 | Feb-24 | Mar-24 | Apr-24 | May-24 | Jun-24 | Jul-24 | Aug-24 | Sep-24 | Oct-24 | Nov-24 | Dec-24 | End of Period Dec-24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Intangible Software | 303 | SO | - | - | - | - | - | - | - | - | - | 154,749,340 | 154,749,340 | 154,749,340 | 154,749,340 | 154,749,340 |

**Depreciation Expense***

| | Account | Factor | Dec-23 | Jan-24 | Feb-24 | Mar-24 | Apr-24 | May-24 | Jun-24 | Jul-24 | Aug-24 | Sep-24 | Oct-24 | Nov-24 | Dec-24 | CY 2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Intangible Software | 404IP | SO | | - | - | - | - | - | - | - | - | 469,944 | 939,888 | 939,888 | 939,888 | 3,289,607 |

**Depreciation Reserve**

| | Account | Factor | Dec-23 | Jan-24 | Feb-24 | Mar-24 | Apr-24 | May-24 | Jun-24 | Jul-24 | Aug-24 | Sep-24 | Oct-24 | Nov-24 | Dec-24 | End of Period Dec-24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Intangible Software | 111IP | SO | - | - | - | - | - | - | - | - | - | (469,944) | (1,409,832) | (2,349,720) | (3,289,607) | (3,289,607) |

| | FERC Acct | End of Period June 2023 | End of Period Dec 2024 | Adjustment | |
|---|---|---|---|---|---|
| **2024 EOP EPIS** | 303 | - | 154,749,340 | **154,749,340** | **Ref. R_2** |
| **Test Period Annualized DEPE** | 404IP | - | 11,278,654 | **11,278,654** | **Ref. R_2** |
| **Test Period Adjusted DEPR** | 111IP | - | (11,278,654) | **(11,278,654)** | **Ref. R_2** |

*Composite Depreciation Rate - INTPSO

7.288% *Composite Depreciation Rate - INTPSO

Exhibit PAC/3302
Cheung/138

Docket No. UE 433
Exhibit PAC/3303
Witness: Sherona L. Cheung

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Sherona L. Cheung**

**Staff Response to PAC Data Request 23**

**July 2024**

Date: July 11, 2024

TO:
DATA REQUEST RESPONSE CENTER
PACIFICORP
825 NE MULTNOMAH STREET STE 2000
PORTLAND, OR 97232
datarequest@pacificorp.com

FROM: Ming Peng
Senior Economist
Rates Division

**OREGON PUBLIC UTILITY COMMISSION**
**Docket No. UE 433 – PacifiCorp Data Request No. 23**

**PAC Data Request No. 23:**

Please refer to Staff/1500, Peng/26, lines 13-15, which states "[The Federal Energy Regulatory Commission (FERC)] has indicated that if the FERC [Allowances for Funds Used During Construction (AFUDC)] rate is different than the state-approved rate, the AFUDC capitalized should be split between utility plant and a regulatory asset. The amount capitalized in utility plant is based on the FERC AFUDC rate." Please provide the source or supporting documentation for this statement.

**OPUC Data Response No. 23:**

Please see attached Staff Attachment A PAC DR 023, **FERC "190074-AVA-Exh1-12-17-19"**, Docket No. PA18-2-000, Exhibit 1, Audit of Avista Corporation's Compliance with its Open Access Transmission Tariff.
Exhibit 1, page 2 and 3:
**(Avista) Noncompliance #2**. Allowance for Funds Used During Construction.

- Avista accounted for the excess arising from higher state-approved AFUDC over AFUDC as computed in accordance with the Commission's accounting regulations as a cost of plant in Account 101, Electric Plant in Service, through Account 107, Construction Work In Progress, instead of recording the excess in Account 182.3, Other Regulatory Assets.

https://apiproxy.utc.wa.gov/cases/GetDocument?docID=10&year=2019&docketNumber=190074

(1) Please see attached Staff Attachment B PAC DR 023, **FERC 2019 REPORT ON ENFORCEMENT, "11-21-19-enforcement"**

https://www.ferc.gov/sites/default/files/2020-05/11-21-19-enforcement.pdf

FERC p. 63.

3. Electric Tariff & Accounting, (Avista) six findings of **noncompliance**.

(2)…. accounting for the excess AFUDC accrual arising from higher state-approved versus Commission-approved AFUDC rates as a cost of plant rather than a regulatory asset in Account 182.3.

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FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

Reply Refer To:
Office of Enforcement
Docket No. PA18-2-000
September 19, 2019

Ms. Marian Durkin
Sr. Vice President, General Counsel,
Chief Compliance Officer, and Corporate Secretary
Avista Corporation
1411 East Mission Avenue
Spokane, WA 99220-3727

Dear Ms. Durkin:

1. The Division of Audits and Accounting (DAA) within the Office of Enforcement (OE) of the Federal Energy Regulatory Commission (Commission) has completed an audit of Avista Corporation (Avista). The audit covered the period January 1, 2015 to December 31, 2018.

2. The audit evaluated Avista's compliance with: (1) the terms, conditions, and rates of its Open Access Transmission Tariff (OATT); (2) the accounting requirements of the Uniform System of Accounts for Public Utilities and Licensees under 18 C.F.R. Part 101; (3) the reporting requirements of the FERC Form No. 1, Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report, under 18 C.F.R. § 141.1; and (4) the regulations regarding Open Access Same-Time Information Systems prescribed in 18 C.F.R. Part 37. The enclosed audit report contains 6 findings, one other matter, and 23 recommendations that require Avista to take corrective action.

3. On September 4, 2019, you notified DAA that Avista does not contest the 6 findings, one other matter, and 23 recommendations in the draft audit report and will submit within 30 days of the issuance of the final audit report a plan for implementing the audit recommendations. A copy of your verbatim response is included as an appendix to this report. I hereby approve the audit report.

4. Avista should submit its implementation plan to comply with the recommendations within 30 days of this letter order. Avista should make quarterly submissions to DAA describing the progress made to comply with the recommendations,

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including the completion date for each corrective action. As directed by the audit report, these submissions should be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after this audit report is issued, and continuing until all the corrective actions are completed.

5. The Commission delegated the authority to act on this matter to the Director of OE under 18 C.F.R. § 375.311. This letter order constitutes final agency action. Avista may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713.

6. This letter order is without prejudice to the Commission's right to require hereafter any adjustments it may consider proper from additional information that may come to its attention. In addition, any instance of non-compliance not addressed herein or that may occur in the future may also be subject to investigation and appropriate remedies.

7. I appreciate the courtesies extended to the auditors. If you have any questions, please contact Mr. Steven D. Hunt, Director and Chief Accountant, Division of Audits and Accounting at (202) 502-6084.

Sincerely,

Larry R. Parkinson
Director
Office of Enforcement

Enclosure

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**Federal Energy Regulatory Commission**
Office of Enforcement
Division of Audits and Accounting

# AUDIT REPORT

## Audit of Avista Corporation's Compliance with its Open Access Transmission Tariff; the Open Access Same-Time Information Systems regulations; the accounting requirements of the Uniform System of Accounts Prescribed for Public Utilities and Licensees; and the reporting requirements of the FERC Form No. 1, Annual Report

Docket No. PA18-2-000
September 19, 2019

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# I. Executive Summary

## A. Overview

The Division of Audits and Accounting (DAA) within the Office of Enforcement of the Federal Energy Regulatory Commission (Commission) has completed an audit of Avista Corporation (Avista). The audit evaluated Avista's compliance with: (1) the terms, conditions, and rates of its Open Access Transmission Tariff (OATT); (2) the accounting requirements of the Uniform System of Accounts for Public Utilities and Licensees under 18 C.F.R. Part 101; (3) the reporting requirements of the FERC Form No. 1, Annual Report of Major Electric Utilities, Licensees and Others (Form 1) and Supplemental Form 3-Q: Quarterly Financial Report, under 18 C.F.R. § 141.1; and (4) the regulations regarding Open Access Same-Time Information Systems (OASIS) prescribed in 18 C.F.R. Part 37. The audit covered the period January 1, 2015 to December 31, 2018. This period was expanded to cover years prior to 2015, where necessary, based on DAA's reviews and DAA's recommendations for corrective actions.

## B. Avista Corporation

Avista, which was incorporated in the state of Washington in 1889 as Washington Water Power Company, is primarily an electric and natural gas utility with certain other business ventures.

Avista Utilities is an operating division of Avista comprising of its regulated utility operations in the Pacific Northwest. Avista Utilities generates, transmits, and distributes electricity and distributes natural gas, serving electric and natural gas customers in eastern Washington and northern Idaho, and natural gas customers in parts of Oregon. Avista Utilities also supplies electricity to a small number of customers in Montana. Avista Utilities generates electricity from facilities that it owns and purchases capacity, energy, and fuel for generation under long-term and short-term contracts to meet Avista's retail customer load obligations. Avista Utilities also sells electric capacity and energy, as well as surplus fuel, in the wholesale market as part of its resource optimization activities. Avista also provides retail electric service in Juneau, Alaska through its wholly-owned subsidiary, Alaska Energy and Resources Company (AERC). AERC and its operating subsidiary, Alaska Electric Light and Power Company, merged with Avista on July 1, 2014.

Avista has a non-regulated business segment, which includes sheet metal fabrication, venture fund investments, real estate investments, and a company that explores markets that could be served with liquefied natural gas, as well as certain other investments of Avista Capital, Inc., a direct, wholly-owned subsidiary of Avista.

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## C. Summary of Compliance Findings and Other Matter

Audit staff's compliance findings and other matter are summarized below. A detailed discussion of audit staff's findings and the other matter are in Sections IV and V of this report. Audit staff found 6 areas of noncompliance and one other matter as follows:

*Noncompliance*

1. Secondary Network Transmission Service – Avista improperly reserved hourly secondary network transmission service 61 times, representing 5,233 MWh, to support off-system sales to non-network customers. Of the 61 requests, 34 requests remained confirmed, representing 3,353 MWh, while 27 requests were annulled. Of these 34 requests, 11 were scheduled for energy delivery, representing 1,395 MWh. As a result, Avista's merchant function was not charged point-to-point (PTP) transmission charges and obtained service with a higher service priority.

2. Allowance for Funds Used During Construction – Avista's methods for calculating and accounting for its AFUDC rate were deficient and caused Avista's AFUDC to exceed the maximum AFUDC permitted by the Commission's regulations, as follows:

    - Avista included revolving credit facility commitment fees (up-front and quarterly) as part of short-term debt interest expense to compute its AFUDC rate. Avista did not have Commission approval, required by Order No. 561-A, to include revolving credit facility commitment fees in the calculation of its AFUDC rate.

    - Avista incorrectly included Account 216.1, Unappropriated Undistributed Subsidiary Earnings, as part of the equity component for the purpose of computing its AFUDC rate.

    - Avista incorrectly included Account 219, Accumulated Other Comprehensive Income (AOCI), as part of the equity component for the purpose of computing its AFUDC rate.

    - Avista used monthly Equity and Long-Term Debt balances in AFUDC rate development instead of the using the balances for Equity and Long-Term Debt existing at the end of the prior year.

- Avista excluded Account 234, Notes Payable to Associated Companies, in the computation of its AFUDC rate instead of including Account 234 as a short-term financing source – i.e., in the short-term debt component for purposes of calculating its AFUDC rate.

- Avista accounted for the excess arising from higher state-approved AFUDC over AFUDC as computed in accordance with the Commission's accounting regulations as a cost of plant in Account 101, Electric Plant in Service, through Account 107, Construction Work In Progress, instead of recording the excess in Account 182.3, Other Regulatory Assets.

As a result of these methods, Avista overstated AFUDC by approximately $19.7 million for the period 2015 through 2017.

3. Accounting for Deferred Income Taxes – AFUDC – Avista's methods for accounting for Deferred Income Taxes related to the equity component of the AFUDC rate were deficient as follows:

   - Avista incorrectly recorded a debit in Account 410.1, Provision for Deferred Income Taxes, based on the amount of the equity component of AFUDC included in income Account 419.1, Allowance for Other Funds Used During Construction, and credited Account 282, Accumulated Deferred Income Taxes – Other Property. Avista should have recorded the deferred tax debit amount in Account 182.3, Other Regulatory Assets.

   - Avista should have recorded a gross up for the income taxes related to the equity component of AFUDC in Account 182.3, Other Regulatory Assets, and a related offset as a deferred income tax liability in Account 283, Accumulated Deferred Income Taxes – Other.

   As a result of the foregoing improper accounting, Avista overstated the Deferred Income Tax expense included in its Income Statement for 2015 through 2017 by approximately $8.4 million.

4. Capitalization of System Planning Costs – Avista improperly capitalized system planning costs of approximately $2.8 million as a cost of plant through its CWIP between 2014 and 2017. When subsequently correcting this error, by removing approximately $2.6 million from the cost of plant, Avista did not remove the related accumulated provision for depreciation, current and deferred income taxes, and AFUDC.

5. Asset Retirement Obligations – Avista improperly accounted for certain items related to its Asset Retirement Obligations (ARO). Specifically, Avista did not record Asset Retirement Cost (ARC) depreciation expense in Account 403.1, Depreciation Expense, and ARO accretion expense in Account 411.10, Accretion Expense. Instead, Avista recorded those expenses directly in Account 182.3, Other Regulatory Assets.

6. FERC Form No. 1 Reporting – Avista did not comply with the instructions on page 398, Purchase and Sale of Ancillary Services, on its FERC Form No. 1 filings. This deficient reporting affected the reliability of information reported in Avista's FERC Form No. 1 submissions.

*The Other Matter*

1. Use of Transmission Service Numbers – Avista used Transmission Service Numbers (TSN), in addition to Transmission Service Requests (TSR) created in OASIS, to facilitate scheduling of transmission service under certain circumstances. TSRs created in OASIS provide more transparency than TSNs, which are created outside of OASIS. During the audit, Avista significantly reduced the number of active TSNs, and Avista should continue to evaluate TSN use and reduce the use of TSNs when possible.

## D. Summary of Recommendations

Audit staff's recommendations to remedy the audit findings are summarized below. Details are in Sections IV and V of this report. Audit staff recommends that Avista:

*Secondary Network Transmission Service*

1. Develop and implement controls to ensure that Avista neither requests nor approves network transmission service and secondary network transmission service for any purpose other than to serve network customers.

2. Enhance training for its marketing function employees responsible for reserving and/or scheduling secondary network service to ensure that secondary network service is only reserved to serve Avista's native load customers, unless reserved on behalf of another network customer pursuant to an executed agent agreement.

3. Enhance training for its transmission function employees responsible for approving transmission schedules to ensure network transmission customers,

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including Avista's marketing function, properly use secondary network service.

*Allowance for Funds Used During Construction*

4. Revise and implement procedures to ensure its AFUDC rate calculation is consistent with Electric Plant Instructions No. 3(17), Order Nos. 561 and 561-A, and other applicable Commission accounting regulations.

5. Revise and implement procedures to ensure that Account 216.1 and Account 219 are excluded from the equity components used to derive the AFUDC rate.

6. Revise and implement procedures to ensure that the year-end amounts reported on Avista's FERC Form No. 1 filings are used to compute the AFUDC rate in accordance with the Commission's accounting regulations.

7. Revise and implement procedures to ensure that the AFUDC amount capitalized as a cost of plant is computed in accordance with the Commission's accounting regulations.

8. Provide training to appropriate employees on AFUDC computation in accordance with the Commission's accounting regulations and Avista's revised procedures.

9. Recalculate AFUDC amounts in accordance with the Commission's accounting regulations from January 1, 2010 (effective date of current fixed transmission rates) to the present, determine the excess amount capitalized by Avista, determine the impacts on other accounts due to over-capitalization, and submit correcting journal entries to the DAA for review and approval.

*Accounting for Deferred Income Taxes - AFUDC*

10. Revise and implement Avista's accounting policies and procedures relating to Deferred Income Taxes to comply with the Commission's accounting regulations.

11. Provide training to appropriate employees on accounting procedures related to AFUDC and related income taxes.

12. Provide the amount of Deferred Income Taxes on the AFUDC Equity Component flowed through since January 1, 2010 (effective date of current fixed transmission rates), and the amount that should have been included in

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Account 182.3, Other Regulatory Assets, as of December 31, 2017, and submit detailed analyses to the DAA for review and approval.

13. Report the accounting change in 2018 including the impact on annual balances reported on prior Form No. 1 filings as a note on the next Form No. 1.

14. Inform DAA about any state rate treatment addressing Avista's incorrect accounting for Deferred Income Tax Expense prior to January 1, 2018. Provide details of any such state actions with supporting documentation.

15. Submit journal entries, if appropriate, related to any state commissions' actions to the DAA for review and approval.

*Capitalization of System Planning Costs*

16. Revise and implement procedures to effect correction of errors including corrections to accounts which require Commission approval.

17. Provide enhanced training to appropriate staff on procedures for corrections including requirements to get Commission approval.

18. Submit journal entries to a) remove the remaining over-capitalized system planning costs from the cost of plant, b) remove appropriate accumulated depreciation from accumulated provision for depreciation, and c) correct related Accumulated Deferred Income Tax Account balances, for DAA review and approval.

*Asset Retirement Obligations*

19. Revise and implement policies and procedures to ensure Avista properly accounts for ARO-related costs in accordance with the Commission's accounting regulations.

*FERC Form No. 1 Reporting*

20. Revise and strengthen documented policies, procedures, and practices to help ensure information in its FERC Form No. 1 submissions is correct, accurate, and consistent with the instructions of the form.

21. Provide training to staff on the revised FERC Form No. 1 policies, procedures, and practices. Also, develop a training program that supports the provision of periodic training in this area, as needed.

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*Use of Transmission Service Numbers*

22. Continue to evaluate and take actions to reduce the use of TSNs.

23. Provide training to transmission employees on OATT requirements and implement an ongoing process to ensure that TSNs are used for limited scheduling purposes where a valid adjacent commercial path TSR is not available in OASIS.

## E. Compliance and Implementation of Recommendations

Audit staff further recommends that Avista submit the following for audit staff's review:

- A plan for implementing the audit recommendations within 30 days after the final audit report is issued in this docket;

- Quarterly reports to DAA describing Avista's progress in completing each corrective action recommended in the final audit report. Quarterly nonpublic submissions should be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after the final audit report in this docket is issued, and continuing until completion of all recommended corrective actions; and

- Copies of any written policies and procedures developed in response to the recommendations in the final audit report. These documents should be submitted for audit staff's review in the first quarterly filing after Avista completes such written policy or procedure.

# II. Background

## A. Avista Transmission Operations

Avista maintains a Commission-approved OATT defining terms, conditions, and rates under which Avista provides services related to its transmission facilities.[1] Under its OATT, Avista offers two types of transmission service, Point-to-Point Transmission Service (PTP) and Network Integration Transmission Service (NITS), and seven types of ancillary services. PTP allows Avista customers to receive capacity and energy at designated point(s) of receipt and transfer such capacity and energy to designated point(s) of delivery on either a firm or non-firm basis. The minimum term of firm PTP is one day. In addition, Avista offers non-firm PTP for periods ranging from one hour to one month. NITS allows a network customer to deliver capacity and energy, either from its designated network resources to service its designated network load on a firm basis, or from its non-designated resources to service its designated network load on a non-firm basis.

Avista owns and operates approximately 19,000 miles of primary and secondary electric distribution lines providing service to retail customers. It has an electric transmission system consisting of 685 miles of 230 kV line and 1,565 miles of 115 kV line. It also owns an 11 percent interest in approximately 500 miles of a 500 kV line between Colstrip, Montana and Townsend, Montana.[2] Avista's transmission and distribution systems also include numerous substations with transformers, switches, monitoring and metering devices, and other equipment. The 230 kV lines are the backbone of Avista's transmission grid and are used to transmit power from generation resources – including the Noxon Rapids, Cabinet Gorge, and Mid-Columbia hydroelectric projects – to the major load centers in Avista's service area, as well as to transfer power between points of interconnection with adjoining electric transmission systems. These 230 kV lines interconnect at various locations with the systems of the Bonneville Power Administration (BPA), Grant County PUD, PacifiCorp, NorthWestern Energy, and Idaho Power Company. These interconnection locations serve as points of delivery for power from generating facilities outside of Avista's service area, including the Colstrip Generating Plant near Colstrip, Montana,[3] the Coyote Springs 2 Generating

[1] *See* Avista Corp., FERC Electric Tariff Volume No. 8 (7.0.0).

[2] The other owners of the 500 kV Colstrip Transmission Line are Puget Sound Energy, Portland General Electric, NorthWestern Corporation and PacifiCorp.

[3] Colstrip Generating Station consists of four separate coal-fired generating units with a combined nameplate capacity of 2,272 MW. Colstrip is jointly owned by Puget Sound Energy, Talen Energy, Portland General Electric, Avista, NorthWestern

Plant near Boardman, Oregon, and the Lancaster Plant near Rathdrum, Idaho. These 230 kV lines also provide a means for Avista to optimize resources by entering into short-term purchases and sales of power with entities within and outside of the Pacific Northwest.

Avista's 115 kV lines provide for transmission of energy and the integration of smaller generation facilities with Avista's service-area load centers, including the Spokane River hydroelectric projects, Kettle Falls projects, Rathdrum, Boulder Park, and Northeast facilities. These lines interconnect with the systems of BPA, Chelan County PUD, Columbia Basin Hydropower (which operates the hydroelectric facilities owned by three Columbia Basin Irrigation Districts), Grant County PUD, NorthWestern Energy, PacifiCorp, and Pend Oreille County PUD.

## B. Ancillary Services

Ancillary services are services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of Avista's transmission system. Avista is required under its OATT to provide, and the transmission customer is required to purchase, the following ancillary services: (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources. Avista has not determined the cost of providing these services, and these services are not separately billed by Avista.

Avista is also required to offer to a transmission customer serving load within Avista's control area, these other ancillary services: (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve - Spinning, and (iv) Operating Reserve - Supplemental. In addition, Avista provides Generator Imbalance Service when a difference occurs between the output of a generator in Avista's control area and the delivery schedule of the generator. The Energy Imbalance and Generator Imbalance Services charges are based on the Intercontinental Exchange (ICE) Mid-Columbia Index and various deviations bands established by Avista, whereas the other ancillary services are billed at predetermined rates.[4] Transmission customers serving load within Avista's control area are required to acquire these ancillary services, whether from Avista, from a third party, or by self-supply. BPA, Avista's sole NITS customer, has made certain alternative arrangements and does not acquire all ancillary services offered by Avista.

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Corporation, and PacifiCorp. Avista owns 15% of Colstrip generating plant units 3 and 4, which have 778 MW of nameplate capacity each.

[4] ICE is an American company that owns exchanges for financial and commodity markets, and operates 12 regulated exchanges and marketplaces.

## C. Trading Activities

Avista engages in energy trading activities to optimize its energy resources. Avista's merchant function has organized a power supply front office responsible for term and day ahead trading, power scheduling, settlement analysis, and real-time merchant operations. Avista's trading activities involve securing least-cost power for its native load, as well as engaging in cost-effective energy trades with third parties.

The term and day ahead trading transactions are governed by Avista's electric position and hedging strategy approved by Avista's Risk Management Committee. These transactions, comprising financial and physical power products, are executed through ICE, third-party brokers or bilateral counter-party transactions.

The power scheduling and settlement functions coordinate to obtain the required transmission to facilitate term and preschedule transactions. These functions determine any temporary resource undesignations and deliver preschedule plans to Avista's real-time merchant function employees who are responsible for real-time generation dispatch and optimization, and several other related activities.

Avista's back office, led by Avista's Director of Finance, monitors the creditworthiness of counterparties. Avista has written policies and procedures that require Avista to confirm that counterparties are approved for credit, and appropriate contractual terms have been agreed to between Avista and a counterparty before trading transactions can occur. The back office is also responsible for billings, collections, and appropriate accounting for trading transactions. All wholesale transactions are captured in Avista's system of records, called Nucleus, for purposes of tracking credit exposure, accounting, and invoice processing, in addition to scheduling.

## D. Transmission Rates

Avista established its current PTP rates as fixed rates in 2009 based on its historical expenses and rate base. Avista's PTP rates were approved by the Commission on December 16, 2009,[5] and became effective on January 1, 2010. Avista's PTP customers pay a separate charge for PTP on the Colstrip segment, which is comprised of 500 kV transmission facilities between Colstrip and Townsend, Montana, based on fixed rates effective January 1, 2010.

Avista's NITS rates also became effective on January 1, 2010 and were derived from a predetermined revenue requirement of $49.4 million, which is allocated to

[5] *Avista Corp.*, Docket No. ER10-169-000 (Dec. 16, 2009) (delegated letter order).

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Avista's NITS customers based on their share of loads. NITS rates on the Colstrip segment were approved with a predetermined revenue requirement of $3.2 million, which is allocated to NITS customers on their share of loads on that segment.

Avista's ancillary service rates for Regulation and Frequency Response, Energy Imbalance, Operating Reserve - Spinning, and Operating Reserve - Supplemental became effective on January 1, 2010. The Commission approved a modification to these rates in 2012[6] and an increase to these rates in 2016.[7]

## E. Available Transfer Capability Calculation

Avista posts the Available Transfer Capability (ATC) values for all transmission paths on its OASIS, and the ATC value informs transmission customers about the amount of power available to move across a transmission path for commercial activity. Mathematically, ATC is defined as Total Transfer Capability (TTC) less Transmission Reliability Margin (TRM) less Capacity Benefit Margin (CBM) less existing transmission commitments. TTC indicates the amount of power that can be transferred over the interconnected transmission network in a reliable manner while meeting a specific set of pre-and post-contingency system conditions. Avista's TTC calculation must conform to the Western Electricity Coordinating Council's (WECC's) "Procedures for Regional Planning Project Review and Rating Transmission Facilities" and WECC's Reliability Criteria.[8] TRM indicates the amount of transmission transfer capability needed to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. CBM is the amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. Avista currently sets TRM and CBM to zero for the purpose of its ATC calculation.

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[6] *Avista Corp.*, Docket No. ER12-1940-000 (July 24, 2012) (delegated letter order).

[7] *Avista Corp.*, Docket No. ER16-2090-000 (August 17, 2016) (delegated letter order).

[8] WECC promotes Bulk Electric System reliability in the Western Interconnection. WECC is the Regional Entity responsible for compliance monitoring and enforcement. In addition, WECC provides an environment for the development of Reliability Standards and the coordination of the operating and planning activities of its members as set forth in the WECC Bylaws.

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Avista calculates ATC on a contract basis, consistent with its posted ATC Implementation Document. Avista conducts Seasonal Operating Studies, at least two times per year, to evaluate the expected operating conditions and system configuration for the upcoming summer and winter operating seasons. Data from these studies is reflected in the determination of TTC; thus, any changes to TTC will result in a change to ATC.

## F. Mid-Columbia Hub Operations

Avista's transmission network is connected to the Mid-Columbia hub (Mid-C), which is a common point for commercial energy trading in the West. Avista uses pseudo ties to integrate its contracted generation resources at Mid-C with its system loads into a single balancing authority. Avista's contracted generation resources for the audit period at Mid-C included a total of 180 MW of capability from Grant PUD, Chelan PUD, and Douglas PUD hydro-electric projects. Pseudo ties and dynamic schedules are dynamic transfers that define how an entity schedules power over an arranged transmission path. Avista uses pseudo ties to connect power generation from the Colstrip Generating Plant and the Coyote Springs 2 Generating Plant. Avista uses dynamic schedules over reserved transmission capacity to transfer the energy at the Mid-C to its major load centers. At the end of each hour, Avista records the actual energy flow between the Mid-C and the Avista system and updates the dynamic schedules according to established e-Tagging protocols.

# III. Introduction

## A. Objectives

The audit evaluated Avista's compliance with the requirements of its OATT and with the Commission's accounting, financial reporting, and OASIS rules and regulations. The audit covered the period January 1, 2015 to December 31, 2018.

## B. Scope and Methodology

Audit staff performed these actions to facilitate testing and evaluating Avista's compliance with Commission requirements relevant to audit objectives:

- *Reviewed Public Information* – Conducted an extensive review of public information before commencing the audit. The review provided audit staff with an understanding of Avista's operations and finances, merger, significant contracts, prior audit issues, and other key regulatory and business activities. Examples of materials reviewed include Avista's annual reports and SEC Forms 10-K and 10-Q, FERC Form No. 1, prior FERC audit reports, company-related websites, and other relevant regulatory and media sources.

- *Identified Audit Criteria* – Identified audit criteria including Commission rules, regulations, and other requirements necessary to evaluate compliance with the audit objectives.

- *Issued Data Requests* – Issued data requests to Avista to collect audit evidence and information. The information related to internal policies; transmission operations, procedures, and controls; business practices; risk management; corporate structure; contractual agreements; financial accounting and reporting activities; corporate compliance; regulatory filings; and other pertinent information. The evidence and information were used to test and evaluate compliance with Commission requirements relevant to audit objectives.

- *Conducted Teleconferences* – Held multiple teleconferences with Avista employees to discuss audit objectives, testing, data request responses, technical and administrative matters, and compliance concerns.

- *Attended Site Visits* – Made two site visits to Avista's headquarters in Spokane, WA to discuss and observe controls and procedures related to audit objectives.

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- *Internal Commission Collaboration* – Conferred with other Commission staff on compliance issues to ensure audit findings were consistent with Commission precedent and policy.

Audit staff performed specific actions to evaluate Avista's compliance with select OATT requirements, including review of:

- *Transmission Planning* – Reviewed Avista's transmission planning process and cost allocation study cases to determine whether Avista followed the principles adopted in Order No. 1000 for new projects. Audit staff also reviewed Avista's compliance with requirements in its OATT's Attachment K, Transmission Planning Process.

- *Point-to-Point and Network Integrated Transmission Service* – Reviewed Avista's merchant function's activities to determine whether Avista properly used network service only to serve native load customers and not to support off-system sales.

- *Network Resource Designation/Undesignation Process* – Reviewed Avista's network resource designation/undesignation practice to determine whether Avista properly undesignated network resources when using those resources to supply off-system sales. Audit staff also reviewed the transmission services related to these off-system sales.

- *ATC Calculation Inputs* – Reviewed inputs into Avista's ATC calculation including, but not limited to, transmission capacity set-aside amounts and other ATC components to determine whether Avista timely and accurately updated ATC values posted on its OASIS.

- *Generation Interconnection Requests* – Reviewed generator interconnection requests and the associated queue to determine whether Avista met its obligations to timely communicate with customers pertaining to their requests consistent with the generation interconnection procedures contained in OATT Attachments M, N, and O.

- *Mid-Columbia Hub* – Reviewed Avista's Mid-C activities and related transmission services to understand how Avista operates resources and moves power at this major regional hub. Specifically, audit staff reviewed Avista's own generation and purchases at Mid-C and determined whether Avista was providing the proper transmission services to its merchant function and other customers in moving power from these resources.

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- *Transmission Service Requests* – Reviewed Avista's transmission function's activities to determine whether it provided transmission/ancillary services on a non-discriminatory basis to affiliates, including Avista's merchant function, and non-affiliates.

- *Dynamic Schedules and Unreserved Transmission Service (After-the-Fact Tags)* –Reviewed Avista's transmission operations to see whether after-the-fact tags are used at Avista and, if so, determine whether there were any related compliance concerns around the possible misuse of transmission services.

- *Ancillary Services* – Reviewed Avista's compliance with the rates, terms, and conditions under its different OATT Ancillary Service Schedules. As part of this review, audit staff reviewed Avista's processes and procedures for ancillary services to determine whether Avista allowed its customers to make a comparable arrangement themselves (self-supply) for certain ancillary services specified in Avista's OATT.

- *Electric-Gas Coordination* – Reviewed Avista's processes and procedures for electric-gas coordination as natural gas makes up 35 percent of Avista's total generation mix.

- *Open Access Same-Time Information System* – Reviewed information posted on Avista's OASIS to determine compliance with Part 37 of the Commission's regulations. Specifically, audit staff reviewed select items, including, but not limited to: transmission capacity information; designation/re-designation/termination of network resources; curtailments; transmission schedules; discretionary logs; and information on transmission planning and interconnections. Other items reviewed included:

    - *Posted Paths* – Verified whether Avista posted all paths that should be posted, such as paths involving interconnections.

    - *Study List* – Verified whether Avista posted on its OASIS a list of system-planning studies, facilities studies, and specific network impact studies performed for customers or the entity's own network resources.

    - *Unavailability of ATC* – Verified whether Avista posted a narrative explanation of the reason for the unavailability of ATC when the monthly and yearly capability remained unchanged at a value of zero for a period of six months.

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- *Daily Load* – Verified whether Avista posted on a daily basis, its load forecast, including underlying assumptions, and actual daily peak load for the prior day.

- *Ancillary Service Offerings and Prices* – Verified whether Avista posted any ancillary service provided or offered under Avista's OATT with the price of that service.

- *Denied Service Request* – Verified whether Avista posted the reason for any denied service request and kept the information to support the denial.

- *Transaction Curtailment* – Verified whether Avista posted a notice of each transaction curtailment and stated the reason why the transaction could not be continued or completed.

- *Notice of Transfers of Personnel* – Verified whether Avista posted the notices of transfers of personnel between transmission function and merchant function.

- *Discretionary Logs* – Verified whether Avista posted a log detailing any circumstance in which Avista or its agents exercised its discretion under any terms of Avista's OATT.

- *Generation Interconnection Queue* – Verified whether Avista posted a list of all interconnection requests consistent with its OATT requirements and kept the list up to date.

- *Standards of Conduct* – Reviewed off-OASIS communications between Avista's transmission function and merchant function employees, such as e-mails, instant messages, and voice recordings, to determine whether sufficient controls were in place to prevent merchant function employees from obtaining non-public transmission function information.

- *Accounting and Financial Reporting* – Reviewed Avista's accounting and financial reporting for items included in Avista's Annual Transmission Revenue Requirement in its OATT's Attachment H. Audit staff also reviewed the operational aspects of those revenue requirement items to understand how Avista's transmission operations feed into the revenue requirement and, ultimately, feed into Avista's stated transmission rates in Schedules 7 and 8. As part of this review, audit staff determined whether Avista was complying with the Commission's accounting and financial reporting regulations for select items.

# IV. Findings and Recommendations

## 1. Secondary Network Transmission Service

Avista improperly reserved hourly secondary network transmission service 61 times, representing 5,233 MWh, to support off-system sales to non-network customers. Of the 61 requests, 34 requests remained confirmed, representing 3,353 MWh, while 27 requests were annulled. Of these 34 requests, 11 were scheduled for energy delivery, representing 1,395 MWh. As a result, Avista's merchant function was not charged PTP transmission charges and obtained service with a higher service priority.

### Pertinent Guidance

Avista's OATT, Part III, Network Integration Transmission Service – Preamble, states, in part:

> Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff.[9]

Avista's OATT, section 28.4, Secondary Service, states, in part:

> The Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Secondary Service shall not require the filing of an Application for Network Integration Transmission Service under the Tariff. However, all other requirements of Part III of the Tariff (except for transmission rates) shall apply to secondary service.[10]

Avista's OATT, section 28.6, Restrictions on Use of Service, states, in part:

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[9] Avista Corp., FERC Electric Tariff Volume No. 8, Part III, Network Integration Transmission Service, Preamble (6.0.0).

[10] Avista Corp., FERC Electric Tariff Volume No. 8, Part III, Network Integration Transmission Service, Section 28.4, Secondary Service (6.0.0).

> The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System.[11]

**Background**

Avista's OATT provides secondary network transmission service to its network customers to serve network load from non-designated network resources on an as-available basis at no additional charge. A network customer can only reserve secondary network transmission service in this manner to serve its designated network load and cannot reserve secondary network transmission service to support a sale to non-designated load, which is referred to as an off-system sale. In accordance with Avista's OATT, PTP transmission service, which involves a charge and has a lower priority than secondary network transmission service, must be used to support an off-system sale.

In its review of secondary network transmission service used by Avista's merchant function, audit staff determined that Avista's merchant function reserved and confirmed 61 secondary network transmission service hourly requests during the audit period to deliver energy from Avista's transmission system to non-network customers, representing a combined total of 5,233 MWh of off-system sales. Of the 61 confirmed requests, 27 were annulled while 34 remained confirmed, representing 3,353 MWh. Of the 34 requests, 11 were scheduled for energy delivery, representing 1,395 MWh. All 34 confirmed reservations had higher curtailment priority that would potentially displace any other non-affiliated, non-firm PTP requests. However, audit staff did not identify any evidence that showed improper displacement of other requests and, hence, concluded that there had been no harm to competition.

The fact that these improper reservations were scheduled/requested and approved demonstrated that the controls Avista had in place to prevent the misuse of secondary network transmission service could be enhanced. Avista's merchant function should have requested, and its transmission function subsequently should have approved, short-term firm PTP transmission service instead of secondary network transmission service since the use of transmission service was for sales to non-designated loads. Audit staff determined that by improperly requesting and confirming the use of secondary network

[11] Avista Corp., FERC Electric Tariff Volume No. 8, Part III, Network Integration Transmission Service, Section 28.6, Restrictions on Use of Service (6.0.0).

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transmission service, Avista's merchant function did not pay short-term PTP transmission charges and obtained service with a higher service priority.

Avista's billings to network customers were not impacted by the use of secondary network transmission service as Avista had a predetermined NITS revenue requirement since January 1, 2010. However, revenues from short-term PTP transmission service are applied as an offset in determining Avista's network service revenue requirement. Audit staff points out that such errors may impact the PTP transmission service revenue data used in Avista's future transmission rate developments.

**Recommendations**

We recommend that Avista:

1. Develop and implement controls to ensure that Avista neither requests nor approves network transmission service and secondary network transmission service for any purpose other than to serve network customers.

2. Enhance training for its marketing function employees responsible for reserving and/or scheduling secondary network service to ensure that secondary network service is only reserved to serve Avista's native load customers, unless reserved on behalf of another network customer pursuant to an executed agent agreement.

3. Enhance training for its transmission function employees responsible for approving transmission schedules to ensure network transmission customers, including Avista's marketing function, properly use secondary network service.

**2. Allowance for Funds Used During Construction**

Avista's methods for calculating and accounting for its AFUDC rate were deficient and caused Avista's AFUDC to exceed the maximum AFUDC permitted Avista by the Commission's regulations, as follows:

- Avista included revolving credit facility commitment fees (up-front and quarterly) as part of short-term debt interest expense to compute its AFUDC rate. Avista did not have Commission approval, required by Order No. 561-A, to include revolving credit facility commitment fees in the calculation of its AFUDC rate.

- Avista incorrectly included Account 216.1, Unappropriated Undistributed Subsidiary Earnings, as part of the equity component for the purpose of computing its AFUDC rate.

- Avista incorrectly included Account 219, Accumulated Other Comprehensive Income (AOCI), as part of the equity component for the purpose of computing its AFUDC rate.

- Avista used monthly Equity and Long-Term Debt balances in AFUDC rate development instead of the using the balances for Equity and Long-Term Debt existing at the end of the prior year.

- Avista excluded Account 234, Notes Payable to Associated Companies, in the computation of its AFUDC rate instead of including Account 234 as a short-term financing source – i.e., in the short-term debt component for purposes of calculating its AFUDC rate.

- Avista accounted for the excess arising from higher state-approved AFUDC over AFUDC as computed in accordance with the Commission's accounting regulations as a cost of plant in Account 101, Electric Plant in Service, through Account 107, Construction Work In Progress, instead of recording the excess in Account 182.3, Other Regulatory Assets.

As a result of these methods, Avista overstated AFUDC by approximately $19.7 million for the period 2015 through 2017.

**Pertinent Guidance**

Order No. 561, Order Adopting Amendment to Uniform System of Accounts for Public Utilities and Licensees and for Natural Gas Companies, states in part:

> The balances of long-term debt, preferred stock, and common equity for use in the formula for the current year will be the balances in such accounts at the end of the prior year…
>
> We agree that in some instances, [compensating balances and commitment fees] could properly be considered in determining the effective cost rate for short-term debt for use in the formula. However, primarily because of measurement problems, we do not believe that specific recognition should be given in the general rule. Instead, where an individual company has a written agreement and can support the fact that compensating balances and commitment fees are necessary in order to obtain favorable short-term financing and are not considered in its rate proceedings, we will permit an adjustment to the nominal short-term interest rates to reflect this additional cost.[12]

18 C.F.R. Part 101, Electric Plant Instructions 3(A)(17), Allowance for Funds Used during Construction, states in part:

> Allowance for funds used during construction includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds.
>
> The rates shall be determined annually. The balances for long-term debt, preferred stock and common equity shall be the actual book balances as of the end of the prior year.

Order No. 469, Order Amending Uniform System of Accounts for Public Utilities and Licensees (Class A and Class B) and Natural Gas Companies (Class A and Class B) and FPC Annual Report Forms No. 1 and No. 2, states in part:

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[12] *Amendments To Uniform System of Accounts for Public Utilities and Licensees and for Natural Gas Companies (Classes A, B, C and D) to Provide for the Determination of Rate for Computing the Allowance for Funds Used During Construction and Revision of Certain Schedule Pages of FPC Reports*, Order No. 561, 57 FPC 608, at 610-611 (1977), *reh'g denied*, Order No. 561-A, 59 FPC 1340 (1977), *order on clarification*, 2 FERC ¶ 61,050 (1978).

> It will continue to be the Commission's policy that the undistributed earnings of subsidiaries are to be excluded from the common stockholder's equity in determining rate of return.[13]

18 C.F.R. Part 101, General Instruction No. 23(C), Accounting for Other Comprehensive Income, states:

> When it is probable that an item of other comprehensive income will be included in the development of cost-of-service rates in subsequent periods, that amount of unrealized losses or gains will be recorded in Accounts 182.3 or 254 as appropriate.

**Background**

Audit staff reviewed Avista's process and policy for computing AFUDC rate and the application of such rates to construction projects. Through its review, audit staff identified deficiencies in Avista's methods for calculating and accounting for AFUDC in the areas described below. These deficiencies caused AFUDC calculated by Avista to exceed the maximum AFUDC permitted by the Commission's regulations.

*Revolving Credit Facility*

Avista had a practice of using revolving credit facilities to finance its operations. A revolving credit facility of $400 million was available to Avista during the audit period to finance its operations. Avista's daily average use of the revolving credit facility during 2015 through 2017 was approximately $178 million. The terms of the credit agreement required Avista to pay both an up-front fee and additional quarterly commitment fees based on the *unused* balance at the end of each quarter. When Avista used the revolving credit facility, it was also charged interest on the amount outstanding each month until Avista paid off the outstanding balance.

Avista accounted for the upfront fee and the quarterly commitment fees on the unused balance as well as the monthly interest payments for the credit balances outstanding by debiting Account 431, Other Interest Expense, and ultimately crediting Account 131, Cash.

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[13] *Revisions in Uniform System of Accounts, and Annual Report Forms No. 1 and No. 2 to Adopt the Equity Method of Accounting for Long-Term Investments in Subsidiaries*, Order No. 469, 49 FPC 326, at 327 (1973).

In light of Avista's short-term financing arrangements, audit staff reviewed the individual components and calculations of Avista's AFUDC rate to determine whether Avista was in compliance with the Commission's accounting regulations. Audit staff determined that Avista's components of short-term interest expense included amortization of the total of the up-front fee and the quarterly commitment fees for the $400 million revolving credit facility agreement obtained by Avista. By including the total of the up-front fee and the quarterly commitment fees on unused credit balances, Avista overstated the short-term interest component in its calculation of its AFUDC rate during the audit period.

The Commission, in Order No. 561 and Order No. 561-A, stated that compensating balance and commitment fees should be excluded from the short-term debt interest component of the AFUDC rate computation, unless an entity obtains Commission approval to include these items.[14] Avista did not provide audit staff with any evidence that it had obtained Commission approval to include these costs in its AFUDC rate calculations. Since Avista did not seek or obtain Commission approval to include commitment fees in its AFUDC calculation, or otherwise deviate from the Commission's express prohibition on including these items in an AFUDC rate calculation, it was improper for Avista to include these amounts in its AFUDC rate calculation.

*Equity Component of AFUDC Rate*

In its review of the equity component that was included in Avista's AFUDC rate calculations, audit staff determined that Avista incorrectly used balances from Account 219 and Account 216.1 in deriving the equity component of the AFUDC rate calculation. AFUDC includes the net cost of borrowed funds used for construction purposes and an allowed rate on other funds. Since the gains and losses in Account 219 were *unrealized*, and amounts in Account 216.1 were *undistributed* by Avista's subsidiaries and therefore not available to finance construction, those amounts should not have been considered as

[14] In Order No. 561, the Commission stated that, "we do not believe that specific recognition should be given in the general rule. Instead, where an individual company has a written agreement and can support the fact that compensating balances and commitment fees are necessary in order to obtain favorable short-term financing and are not considered in its rate proceedings, we will permit an adjustment to the nominal short-term interest rates to reflect this additional cost." 57 FPC 608, at 611. In Order No. 561-A, the Commission stated that "Order No. 561 neither changes the Commission's policy with respect to treatment of short-term debt in capitalization used for rate of return purposes nor does it grant blanket approval for recognition of compensating balances and commitment fees in costing short-term debt. The burden of proof is upon the companies to justify such items before they will be permitted." 59 FPC 1340, at 1342.

equity available to Avista for construction in deriving Avista's AFUDC rate. In Order No. 469, the Commission stated that undistributed earnings of subsidiaries are to be excluded from common stockholder equity in determining rate of return.[15] Avista's Account 219 and Account 216.1 had debit, *i.e.*, negative, balances during the audit period, and Avista's inclusion of these debit balances did not result in an overstatement of its equity component in its AFUDC rate calculations.

Additionally, the Commission's accounting regulations require the use of actual book balances as of the end of the previous year in the appropriate equity accounts when computing the AFUDC rate. However, in its equity component for calculating its AFUDC rate during the audit period, Avista used varying monthly amounts that were different from what was reported as prior year ending balances on Avista's FERC Form No. 1 for Account 201, Common Stock Issued, Account 211, Miscellaneous Paid-In Capital, and Account 216, Unappropriated Retained Earnings. Avista should have used the prior year ending balances as reported on its FERC Form No. 1 filings.

*Short-Term Borrowings from Associated Companies*

The Commission's accounting regulations require use of short-term financing as the first source of financing for construction work in progress in deriving the AFUDC rate. Avista had short-term borrowings from its associated companies during the audit period, and it reported those liabilities in Account 234. However, Avista's computation of its AFUDC rate did not include its short-term borrowings from associated companies, leading to Avista understating the short-term debt component in its AFUDC rate calculations. Exclusion of the short-term notes payable to associated companies resulted in an overstatement of the AFUDC in excess of the maximum permitted by the Commission's regulations.

*AFUDC Rate Approved by State Regulators*

Avista operates in Washington, Oregon, and Idaho to provide retail electric and gas distribution services. The guidelines provided by the state commissions for calculating AFUDC rate varied significantly from the Commission's accounting regulations. For example, the Commission's accounting regulations require a regulated entity's short-term financing to be considered as the first source of financing for construction work in progress (meaning that only where an entity's CWIP exceeds its short-term financing will long-term (usually more expensive) financing be used in

[15] *Revisions in Uniform System of Accounts, and Annual Report Forms No. 1 and No. 2 to Adopt the Equity Method of Accounting for Long-Term Investments in Subsidiaries*, Order No. 469, 49 FPC 326, at 327 (1973).

calculating the AFUDC rate), whereas the states' regulations did not have that requirement. Avista computed its AFUDC rate for purposes of its Commission-jurisdictional transmission rates following the states' guidelines, rather than the Commission's regulations, which resulted in AFUDC rate that exceeded the maximum AFUDC rate computed in accordance with the Commission's accounting regulations due to the significantly lower cost of Avista's short-term borrowings compared to its long-term financing. Avista did not provide any evidence of Commission approval for using AFUDC rate that exceeded the maximum AFUDC rate permitted under the Commission's accounting regulations, as indicated in the following table:

AFUDC Capitalization Rate Overstatement Due to All Noncompliant Items

| Year | Maximum Rate per Commission Regulations | Rate Used by Avista | Rate Overstatement |
|---|---|---|---|
| 2015 | 3.67% | 7.32% | 3.65% |
| 2016 | 1.44% | 7.29% | 5.85% |
| 2017 | 2.67% | 7.29% | 4.62% |

*Accounting for AFUDC*

Avista recorded the AFUDC that it calculated in accordance with state, rather than Commission, guidelines as a cost of the plant in service in Account 101, by initially debiting Account 107, Construction Work in Progress – Electric, and crediting Account 432, Allowance for Borrowed Funds Used During Construction, with the AFUDC interest amount as calculated by Avista, and also crediting Account 419.1, Allowance for Other Funds Used During Construction, with any remaining of the total AFUDC amount calculated by Avista that were permitted by state commissions. Instead of debiting its incorrectly calculated AFUDC amount to Account 107, Avista should have recorded – as a debit in Account 107 – the maximum AFUDC permitted under the Commission's accounting regulations, and recorded any surplus amount allowed for retail rate making purposes as a debit to Account 182.3, Other Regulatory Assets. Using the maximum amounts of AFUDC permitted under the Commission's regulations and using the correct accounting entries results in the following AFUDC capitalization for the years in the audit period, compared to that recorded by Avista:

AFUDC Capitalization Overstatement Due to All Noncompliant Items and Accounting

| Year | Maximum Amount of AFUDC per Commission Regulations | AFUDC capitalized | Excess AFUDC capitalized |
|---|---|---|---|
| 2015 | 5,260,639 | 10,965,750 | 5,705,111 |
| 2016 | 1,872,872 | 9,651,510 | 7,778,638 |
| 2017 | 3,443,376 | 9,695,827 | 6,252,451 |
| Total | $ 10,576,887 | $ 30,313,087 | $ 19,736,200 |

**Recommendations**

We recommend that Avista:

4. Revise and implement procedures to ensure its AFUDC rate calculation is consistent with Electric Plant Instructions No. 3(17), Order Nos. 561 and 561-A, and other applicable Commission accounting regulations.

5. Revise and implement procedures to ensure that Account 216.1 and Account 219 are excluded from the equity components used to derive the AFUDC rate.

6. Revise and implement procedures to ensure that the year-end amounts reported on Avista's FERC Form No. 1 filings are used to compute the AFUDC rate in accordance with the Commission's accounting regulations.

7. Revise and implement procedures to ensure that the AFUDC amount capitalized as a cost of plant is computed in accordance with the Commission's accounting regulations.

8. Provide training to appropriate employees on AFUDC computation in accordance with the Commission's accounting regulations and Avista's revised procedures.

9. Recalculate AFUDC amounts in accordance with the Commission's accounting regulations from January 1, 2010 (effective date of current fixed transmission rates) to the present, determine the excess amount capitalized by Avista, determine the impacts on other accounts due to over-

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capitalization, and submit correcting journal entries to the DAA for review and approval.

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### 3. Accounting for Deferred Income Taxes - AFUDC

Avista's methods for accounting for Deferred Income Taxes related to the equity component of the AFUDC rate were deficient as follows:

- Avista incorrectly recorded a debit in Account 410.1, Provision for Deferred Income Taxes, based on the amount of the equity component of AFUDC included in income Account 419.1, Allowance for Other Funds Used During Construction, and credited Account 282, Accumulated Deferred Income Taxes – Other Property. Avista should have recorded the deferred tax debit amount in Account 182.3, Other Regulatory Assets.

- Avista should have recorded a gross up for the income taxes related to the equity component of AFUDC in Account 182.3, Other Regulatory Assets, and a related offset as a deferred income tax liability in Account 283, Accumulated Deferred Income Taxes - Other.

As a result of the foregoing improper accounting, Avista overstated the Deferred Income Tax expense included in its Income Statement for 2015 through 2017 by approximately $8.4 million.

**Pertinent Guidance**

Commission Accounting Instructions AI93-5-000, Accounting for Income Taxes, Section 1, Early Adoption, states in part:

> Entities shall implement SFAS 109 for FERC accounting and reporting purposes no later than fiscal years beginning after December 15, 1992.

Commission Accounting Instructions AI93-5-000, Accounting for Income Taxes, Section 6, Equity AFUDC, states in part:

> An entity shall record the deferred tax liability for the equity component of AFUDC in Account 282, Accumulated Deferred Income Taxes – Other Property, and any corresponding regulatory asset in Account 182.3, Other Regulatory Assets. The regulatory asset is itself a temporary difference for which deferred income taxes shall be recognized and recorded in Account 283, Accumulated Deferred Income Taxes – Other. This accounting shall be followed for the adjustments required upon initial application of the statement and for all amounts of equity AFUDC capitalized in subsequent periods.

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Commission Accounting Instructions AI93-5-000, Accounting for Income Taxes, Section 12, Regulatory Assets and Liabilities, states in part:

> Under the final rule issued in that proceeding (Commission Order No. 552 issued March 31, 1993), an entity is not required to use income statement accounts to recognize regulatory assets and liabilities related to changes in deferred tax assets or liabilities when an equal and corresponding deferred tax asset or liability is recorded.

**Background**

Following issuance of the Statement of Financial Accounting Standards (SFAS) No. 109, the Commission issued Accounting Instructions AI93-5-000, Accounting for Income Taxes, on April 23, 1993, in Docket No. AI93-5-000. The Commission's accounting instruction required public utilities to implement SFAS 109, which required regulated enterprises to recognize a deferred tax liability (1) for tax benefits that are flowed through to customers when temporary differences originate, and (2) for the equity component of AFUDC. Also, SFAS 109 stated that if, as a result of an action by a regulator, it was probable that the future increase or decrease in taxes payable for the above mentioned items would be recovered from or returned to customers through future rates, an asset or liability would be recognized for that probable future revenue, or reduction in future revenue. That asset or liability also is a temporary difference for which a deferred tax liability or asset shall be recognized.

*Deferred Income Taxes on Equity Component of AFUDC*

Avista recorded AFUDC equity components totaling $21,701,905 as allowances for other funds used during construction by debiting Account 107, Construction Work in Progress - Electric (CWIP), and crediting Account 419.1, Allowance for Other Funds Used During Construction, from 2015 through 2017. In addition, Avista recorded a debit of $8,370,405 in Account 410.1 and credited Account 282, to account for the deferred income taxes related to the AFUDC equity component between 2015 and 2017. The amounts debited to CWIP have become or would become a cost component of plant in service and would get recovered through depreciation in different future periods. Accordingly, audit staff finds that the deferred income taxes for AFUDC equity should have been recorded as a regulatory asset in Account 182.3, consistent with the accounting instruction in Docket No. AI93-5-000, rather than Account 410.1 and included in current year net income. Additionally, Avista should have recorded a gross up for the income taxes related to the AFUDC equity by debiting Account 182.3, and crediting Account 283, Accumulated Deferred Income Taxes – Other, as specified in Docket No. AI93-5-000.

AFUDC Equity Component Capitalized and Deferred Income Taxes Flow Through

| Year | AFUDC Equity Component Capitalized | AFUDC Equity Deferred Income Tax Expense | AFUDC Equity Regulatory Asset Recognized |
|---|---|---|---|
| 2015 | 7,961,552 | 2,786,543 | - |
| 2016 | 7,298,983 | 2,890,402 | - |
| 2017 | 6,441,370 | 2,693,460 | - |
| Total | $ 21,701,905 | $ 8,370,405 | $ - |

As shown on the above table, Avista flowed through $8,370,405 as deferred income tax expense through net income, instead of recording the entire amount of $8,370,405 in a regulatory asset account, as required. Avista's overstatement of current year deferred income tax expense may have impacted its state jurisdictional customer rates and its effective income tax rates. Avista agreed to revise its accounting for deferred income taxes to comply with the Commission's accounting guidelines effective January 1, 2018.

**Recommendations**

We recommend that Avista:

10. Revise and implement Avista's accounting policies and procedures relating to Deferred Income Taxes to comply with the Commission's accounting regulations.

11. Provide training to appropriate employees on accounting procedures related to AFUDC and related income taxes.

12. Provide the amount of Deferred Income Taxes on the AFUDC Equity Component flowed through since January 1, 2010 (effective date of current fixed transmission rates), and the amount that should have been included in Account 182.3, Other Regulatory Assets, as of December 31, 2017, and submit detailed analyses to the DAA for review and approval.

13. Report the accounting change in 2018 including the impact on annual balances reported on prior Form No. 1 filings as a note on the next Form No. 1.

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14. Inform DAA about any state rate treatment addressing Avista's incorrect accounting for Deferred Income Tax Expense prior to January 1, 2018. Provide details of any such state actions with supporting documentation.

15. Submit journal entries, if appropriate, related to any state commissions' actions to the DAA for review and approval.

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## 4. Capitalization of System Planning Costs

Avista improperly capitalized system planning costs of approximately $2.8 million as a cost of plant through its CWIP between 2014 and 2017. When subsequently correcting this error, by removing approximately $2.6 million from the cost of plant, Avista did not remove the related accumulated provision for depreciation, current and deferred income taxes, and AFUDC.

**Pertinent Guidance**

18 C.F.R. Part 101, Electric Plant Instructions, Section 4, Overhead Construction Costs, states in part:

> A. All overhead construction costs, such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by others than the accounting utility, law expenses, insurance, injuries and damages, relief and pensions, taxes and interest, shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto, to the end that each job or unit shall bear its equitable proportion of such costs and that the entire cost of the unit, both direct and overhead, shall be deducted from the plant accounts at the time the property is retired.
>
> B. As far as practicable, the determination of pay roll charges includible in construction overheads shall be based on time card distributions thereof. Where this procedure is impractical, special studies shall be made periodically of the time of supervisory employees devoted to construction activities to the end that only such overhead costs as have a definite relation to construction shall be capitalized. The addition to direct construction costs of arbitrary percentages or amounts to cover assumed overhead costs is not permitted.

18 C.F.R. Part 101, Account 561.5, Reliability, Planning and Standards Development, states in part:

> This account shall include the cost of labor, materials used and expenses incurred for the system planning of the interconnected bulk electric transmission systems within a planning authority area.

**Background**

As part of its plant construction activities, Avista recorded engineering and project management overheads related to its plant construction in clearing accounts that were regarded as capital overhead pools and allocated the accumulated balances in those accounts to construction work in progress as overheads. During the audit, Avista disclosed to audit staff that it had improperly capitalized certain system planning costs associated with reliability and load forecasts by including those costs in the capital overheads pool. Avista detected the error in 2017 and determined that the error did not impact capitalization in years prior to 2014. In addressing this error, Avista removed $2,609,186 from the cost of plant to correct over-capitalization.

During site visit interviews and reviews of supporting documents for the correction of over-capitalization, audit staff determined that Avista's correction of the accounting error was incomplete. Avista did not address other items related to the over-capitalization, including an overstatement of AFUDC of $35,032 and impacts on current and deferred income taxes. Audit staff also determined that the amount removed from the cost of plant reflected in Account 101, Electric Plant in Service, was an amount net of depreciation recorded in Account 108, Accumulated Provision for Depreciation. Instead, Avista should have removed: (1) the gross amount over-capitalized from Account 101 ($2,799,261) and (2) the related depreciation amount credited to Account 108 ($156,375). Adjustments to the balance in Account 108 require the Commission's approval.[16]

**Recommendations**

We recommend that Avista:

16. Revise and implement procedures to effect correction of errors including corrections to accounts which require Commission approval.

17. Provide enhanced training to appropriate staff on procedures for corrections including requirements to get Commission approval.

18. Submit journal entries to a) remove the remaining over-capitalized system planning costs from the cost of plant, b) remove appropriate accumulated

[16] *See* 18 C.F.R. Part 101, Account 108, Accumulated Provision for Depreciation of Electric Utility Plant, subpart E (stating: "The utility is restricted in its use of the accumulated provision for depreciation to the purposes set forth above (in subparts A-D of the Account 108 provision). It shall not transfer any portion of this account to retained earnings or make any other uses thereof without authorization by the Commission.").

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depreciation from accumulated provision for depreciation, and c) correct related Accumulated Deferred Income Tax Account balances, for DAA review and approval.

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## 5. Asset Retirement Obligations

Avista improperly accounted for certain items related to its Asset Retirement Obligations (ARO). Specifically, Avista did not record Asset Retirement Cost (ARC) depreciation expense in Account 403.1, Depreciation Expense, and ARO accretion expense in Account 411.10, Accretion Expense. Instead, Avista recorded those expenses directly in Account 182.3, Other Regulatory Assets.

**Pertinent Guidance**

18 C.F.R. § 35.18, Asset Retirement Obligations, states in part:

> (c) A public utility that has recorded asset retirement obligations on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

18 C.F.R. Part 101 - Uniform System of Accounts, Account 182.3, Other Regulatory Assets, states in part:

> B. The amounts included in this account are to be established by those charges which would have been included in net income, or accumulated other comprehensive income, determinations in the current period under the general requirements of the Uniform System of Accounts but for it being probable that such items will be included in a different period(s) for purposes of developing rates that the utility is authorized to charge for its utility services.

18 C.F.R. Part 101 - Uniform System of Accounts, Account 403.1, Depreciation Expense for Asset Retirement Costs, states:

> This account shall include the depreciation expense for asset retirement costs included in electric utility plant in service.

18 C.F.R. Part 101 - Uniform System of Accounts, Account 411.10, Accretion Expense, states:

> This account shall be charged for accretion expense on the liabilities associated with asset retirement obligations included in Account 230, Asset retirement obligations, related to electric utility plant.

**Background**

In Order No. 631, the Commission adopted accounting, reporting, and rate requirements for AROs.[17] An ARO is a legal obligation to retire a tangible long-lived asset. Pursuant to the requirements of Order No. 631, public utilities subject to the Commission's accounting regulations are required to calculate and record an ARO liability in Account 230, Asset Retirement Obligation, and an ARC asset in the electric utility or nonutility plant account, as appropriate, that is associated with the ARO liability.

Audit staff reviewed Avista's accounting processes and procedures to determine whether it accounted for AROs in accordance with the Commission's accounting regulations. As part of this review, audit staff examined the accounting procedures Avista used to recognize AROs, record depreciation of ARCs and accretion of AROs, and record adjustments to costs related to AROs to reflect different periods of recovery of those costs in rates.

Avista initially recorded an ARO by debiting the amount of the ARC to Account 101, Electric Plant in Service, and crediting an equal amount of ARO to Account 230. Avista's AROs were for obligations associated with river structures, PCB-contaminated transformers, ash ponds/landfills, and plant decommissioning.

To record the depreciation on the ARCs, Avista debited Account 182.3 and credited Account 108, Accumulated Provision for Depreciation of Electric Utility Plant. Avista should have debited Account 403.1, Depreciation Expense for Asset Retirement Costs, and credited Account 108, Accumulated Provision for Depreciation of Electric Utility Plant, and recorded adjustments in Account 403.1 to reflect recovery of depreciation in rates in different periods.

To record the accretion expense of AROs, which recognizes the increase in the cost of removing an asset over its useful life, Avista debited Account 182.3 and credited Account 230. Avista should have debited Account 411.10, Accretion Expense, and then recorded adjustments in Account 411.10 to reflect recovery of accretion expense in rates in different periods.

---

[17] *See Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations*, Order No. 631, FERC Stats. & Regs. ¶ 31,142, at P 30 (2003), *order on reh'g,* Order No. 631-A, 104 FERC ¶ 61,183 (2003).

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Lastly, to defer the total ARC depreciation and ARO accretion, Avista should have debited Account 182.3 and credited Accounts 403.1 and 411.10.

**Recommendations**

We recommend that Avista:

19. Revise and implement policies and procedures to ensure Avista properly accounts for ARO-related costs in accordance with the Commission's accounting regulations.

## 6. FERC Form No. 1 Reporting

Avista did not comply with the instructions on page 398, Purchase and Sale of Ancillary Services, on its FERC Form No. 1 filings. This deficient reporting affected the reliability of information reported in Avista's FERC Form No. 1 submissions.

### Pertinent Guidance

18 C.F.R. § 141.1(b)(2)(iii), which discusses FERC Form No. 1, states:

> This report must be filed with the Federal Energy Regulatory Commission as prescribed in § 385.2011 of this chapter and as indicated in the General Instructions set out in this form, and must be properly completed and verified. Filing on electronic media pursuant to § 385.2011 of this chapter is required.

The filing instructions on FERC Form No. 1, Page 398, Ancillary Services Schedule, state in part:

> Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

### Background

Audit staff reviewed Avista's FERC Form No. 1 reports during the audit period for compliance with the filing instructions for the form. During the review, audit staff found that the data reported as Purchases and Sales of Ancillary Services on page 398 of Avista's Form No. 1 filings did not agree with the actual amount of services provided under Avista's OATT. Audit staff conducted additional interviews and discussions on how Avista determined that data and reported that data on the FERC Form No. 1 submissions.

Form 1, Page 398, captures all purchases and sales of the ancillary services specified in Order No. 888 and defined in Avista's OATT.[18] Each line on Page 398

[18] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 77 FERC ¶ 61,080), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 78 FERC ¶ 61,220), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998),

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defines the type of ancillary service that public utilities should report. Instructions to Page 398 require public utilities to provide the billing determinant and unit of measure used to determine the dollar amount of ancillary services reported on each line.

Based on discussions with Avista staff, audit staff determined that Avista inadvertently reported purchases of ancillary services on Line 1 (ancillary services purchased and sold), Line 5 (operating reserve spinning and supplement services purchased and sold), and Line 6 (all other types ancillary services purchased or sold) of Page 398. Avista stated that it did not purchase any ancillary services for use in its provision of services under its OATT; therefore, Avista should not have reported any purchases on those lines. Avista also informed audit staff that the amount reported on Page 398, Line 7 was overstated due to an error. Specifically, the amount reported was in kilowatts instead of the stated unit of measure which was megawatts, and, therefore, related amounts reported were overstated by approximately 1000 times.

**Recommendations**

We recommend that Avista:

20. Revise and strengthen documented policies, procedures, and practices to help ensure information in its FERC Form No. 1 submissions is correct, accurate, and consistent with the instructions of the form.

21. Provide training to staff on the revised FERC Form No. 1 policies, procedures, and practices. Also, develop a training program that supports the provision of periodic training in this area, as needed.

*aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

# V. Other Matter

## 1. Use of Transmission Service Numbers

Avista used Transmission Service Numbers (TSN), in addition to Transmission Service Requests (TSR) created in OASIS, to facilitate scheduling of transmission service under certain circumstances. TSRs created in OASIS provide more transparency than TSNs, which are created outside of OASIS. During the audit, Avista significantly reduced the number of active TSNs, and Avista should continue to evaluate TSN use and reduce the use of TSNs when possible.

**Background**

In Order No. 889, the Commission stated that open access non-discriminatory transmission service requires that information about the transmission system must be made available to all transmission customers at the same time.[19] This means that public utilities must make available to others the same transmission information that is available to their own employees, including their own merchant function, and that is pertinent to decisions they make involving the sale or purchase of electricity.

In its review of Avista's transmission operations, audit staff learned about Avista's use of TSNs, which were created by Avista's transmission function and assigned to its customers, including its own merchant function. Avista assigned TSNs to its customers to schedule transmission service under two primary circumstances: 1) scheduling transmission between two adjacent points for which a transmission segment must exist for scheduling purposes though no such transmission path is posted on OASIS; or 2) accommodating certain pre-Order No. 888 or non-conforming services. The TSNs created for scheduling transmission between two adjacent points were available to multiple customers, and these TSNs were intended for use along with an associated TSR for an adjacent path that was available in OASIS. The TSNs created for certain pre-Order No. 888 or non-conforming services were limited to specific customers, and Avista had a system validation process in place for those customers' specific TSNs to avoid improper use.

Avista had nineteen active TSNs during the audit period. As requested by audit staff, Avista provided a validation check on eight TSNs that were used for scheduling

[19] *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, FERC Stats. & Regs. ¶ 31,035, at III.A (1996) (cross-referenced at 75 FERC ¶ 61,078), *order on reh'g*, Order No. 889-A, FERC Stats & Regs. ¶ 31,049 (cross-referenced at 78 FERC ¶ 61,221), *reh'g denied*, Order No. 889-B, 81 FERC ¶ 61,253 (1997).

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purposes between July 2016 and June 2017. Those eight TSNs were associated with 8,163 transactions during that period. Further review of those transactions showed that all but twenty had valid TSRs from customers for an adjacent path in OASIS. The twenty transactions without a TSR for an adjacent path in OASIS were made by a single non-affiliate customer in error and did not result in actual transmission service. Therefore, customer billings were not impacted. However, to mitigate this weakness identified during the audit, Avista implemented additional system checks to validate customer requests when scheduling TSNs with TSRs for an adjacent path in OASIS to ensure appropriate and limited use of those TSNs.

In 2017, Avista implemented a program to reduce the number of TSNs by replacing pre-Order No. 888 TSNs with customer-submitted TSRs in OASIS or discontinuing the use otherwise. The number of active TSNs has been reduced from nineteen to eight during the audit. Avista plans to continue to use those eight TSNs solely for the purpose of facilitating scheduling of transmission service. As part of its review, audit staff noted several items: (1) Avista provided transparency of its TSN practice by identifying and discussing its active TSNs in section 19 of its Transmission Business Practices document posted on OASIS, (2) the purpose of these TSNs was to facilitate scheduling in limited circumstances, (3) audit staff did not identify any instances of improper use by Avista's merchant function, and (4) Avista made substantive efforts to reduce the use of TSNs during the audit period.

**Recommendations**

We recommend that Avista:

22. Continue to evaluate and take actions to reduce the use of TSNs.

23. Provide training to transmission employees on OATT requirements and implement an ongoing process to ensure that TSNs are used for limited scheduling purposes where a valid adjacent commercial path TSR is not available in OASIS.

# VI. Avista's Response to the Draft Audit Report

September 4, 2019

Steven D. Hunt
Director and Chief Accountant
Division of Audits and Accounting
Office of Enforcement
Federal Energy Regulatory Commission
888 First Street NE. Room 5K-13
Washington, DC 20426

**RE: Docket No. PA18-2-000**
**FERC Compliance Audit of Avista Corporation**

Dear Mr. Hunt:

Avista Corporation ("Avista") submits this response to the draft audit report dated August 20, 2019. Avista agrees with the six findings and one other matter, and agrees to implement the 23 recommendations for the findings and the other matter. Corrective actions have been implemented, are in the process of being implemented, or are planned for all recommendations in the draft audit report.

In response to the recommendations identified in the draft audit report, the attached table outlines Avista's corrective actions taken or planned, and target completion dates for these actions.

Within 30 days after receiving the final audit report, Avista will submit an implementation plan addressing the status of the 23 recommendations, both completed and in progress, and a timeline for completion. Quarterly progress reports to the Division of Audits and Accounting will be provided, with the first report to be submitted by January 31, 2020.

The audit process has provided useful direction to facilitate our compliance with the Commission's policies and requirements. Avista appreciates the audit team's professional, constructive and collaborative approach to this audit.

Respectfully,

Marian Durkin
Sr. Vice President, General Counsel, Corporate Secretary, and
Chief Compliance Officer
Avista Corporation

cc: Nicholas Coughlan
Subramaniam Narthana
Kristen Fleet

Enclosure

Document Content(s)

Exhibit 1



PA18-2-000.PDF.....1-47

# UNITED STATES OF AMERICA
# FEDERAL ENERGY REGULATORY COMMISSION

# 2019 REPORT ON ENFORCEMENT

Docket No. AD07-13-013

Prepared by Staff of the

Office of Enforcement
Federal Energy Regulatory Commission
Washington, D.C.

**NOVEMBER 21, 2019**

The matters presented in this staff report do not necessarily represent the views of the Federal Energy Regulatory Commission, its Chairman, or individual Commissioners, and are not binding on the Commission.

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# INTRODUCTION

The staff of the Office of Enforcement (Enforcement) of the Federal Energy Regulatory Commission (Commission) is issuing this report as directed by the Commission in its Revised Policy Statement on Enforcement.[1] This report informs the public and the regulated community of Enforcement's activities during Fiscal Year 2019 (FY2019),[2] including an overview of, and statistics reflecting, the activities of the four divisions within Enforcement: Division of Investigations (DOI), Division of Audits and Accounting (DAA), Division of Analytics and Surveillance (DAS), and Division of Energy Market Oversight (DEMO).

Enforcement recognizes the importance of informing the public of the activities of its staff, and prepares this report with that objective in mind. Most of the information the public receives about Enforcement's activities comes from public Commission orders approving settlements, orders to show cause, publicly released staff reports, and audit reports. This report summarizes the status and resolution of various matters that were public in FY2019. However, not all of Enforcement's activities result in public actions by the Commission. Like reports in previous years, the FY2019 report provides the public with more information regarding the nature of non-public Enforcement activities, such as investigations that are closed without action, self-reported violations, and examples of surveillance inquiries initiated by DAS that are terminated short of opening an investigation. This report also highlights Enforcement's work administering the audit and accounting programs, monitoring market trends and market competitiveness, and performing surveillance and analysis of conduct in wholesale natural gas and electric markets. In addition, DAA points out a number of areas to help companies enhance compliance programs.

Consistent with Enforcement's continual efforts to increase transparency, this year's report builds on the information presented in previous reports by providing further details about our processes, practices, and specific enforcement matters. Specifically, this year's report includes greater and new details about: (1) DOI's investigatory processes and practices; (2) the Market Monitoring Unit (MMU) referral process, including the rules requiring referrals of potential violations and examples of MMU referrals reviewed by Enforcement staff during FY2019; (3) DAA's audit processes and practices, including the organization and new focus areas of DAA's four audit branches, and the addition of citations to docket numbers for recurring, problematic compliance issues discussed in DAA's Compliance Alerts section of this report; and (4) DAS's processes and practices related to reviewing MMU referrals and data management, and the inclusion of additional examples of DAS inquiries closed with no action.

On September 16, 2019, certain functions performed by DEMO and DAS were realigned within Enforcement, the Office of Energy Policy and Innovation (OEPI), and the Office of the Executive Director (OED). The primary objective of the realignment was to better reflect the key functions and mission statements of the three existing Commission offices. Compliance functions

[1] *Enforcement of Statutes, Regulations and Orders*, 123 FERC ¶ 61,156, at P 12 (2008) (Revised Policy Statement). Enforcement's current organizational chart is attached as Appendix A1 to this report.

[2] The Commission's fiscal year begins October 1 and ends September 30 of the following year. FY2019, the subject of this report, began on October 1, 2018 and ended on September 30, 2019.

performed by DEMO, such as Electric Quarterly Report (EQR) and financial forms administration and market power monitoring, remain in Enforcement under DAA and DAS. Policy-related functions performed by DEMO that were more aligned with the mission of OEPI, such as the Annual State of the Markets Report and seasonal assessments, were transferred to that office under a new Division of Energy Markets Assessments. Additionally, some data management support functions performed by DAS were transferred to the newly created Data Governance Division within OED. This realignment will allow Enforcement staff to be more focused on its core mission: continuing oversight of market activities, investigations, and audits.[3]

[3] Enforcement's organizational chart before this realignment is attached as Appendix A2 to this report.

# OFFICE OF ENFORCEMENT PRIORITIES

The Commission's current Strategic Plan sets forth a mission to account for significant changes in energy supply due to a number of factors, such as the increased availability of domestic natural gas and the emergence and growth of new energy technologies. As the Strategic Plan notes, both the nation's energy infrastructure and energy markets must adapt to these changes to ensure that consumers have access to economically efficient, safe, reliable, and secure energy at a reasonable cost.[4] The Strategic Plan identifies three primary goals to fulfill this mission: (1) ensure just and reasonable rates, terms, and conditions; (2) promote safe, reliable, and secure infrastructure; and (3) support the mission through organizational excellence. To further those goals and assist the Commission in its obligation to oversee regulated markets, Enforcement gathers information about market rules, market participants, and market behavior through its investigations, audits and surveillance. Enforcement also gathers information regarding energy infrastructure, as appropriate. Each of the divisions continues to work to bring entities into compliance with applicable statutes, Commission rules, orders, regulations, and tariff provisions.

In FY2019, Enforcement's priorities continued to focus on matters involving:

- Fraud and market manipulation;
- Serious violations of the Reliability Standards;
- Anticompetitive conduct; and
- Conduct that threatens the transparency of regulated markets.

Conduct involving fraud and market manipulation poses a significant threat to the markets the Commission oversees. Such misconduct undermines the Commission's goal of ensuring efficient energy services at a reasonable cost because the losses imposed by fraud and manipulation are ultimately passed on to consumers. Similarly, anticompetitive conduct and conduct that threatens market transparency undermine confidence in the energy markets and harm consumers and competitors. Such conduct might also involve the violation of rules designed to limit market power or to ensure the efficient operation of regulated markets. Enforcement focuses on preventing and remedying misconduct involving the greatest harm to the public, where there may be significant gain to the violator or loss to the victims.

The Reliability Standards established by the North American Electric Reliability Corporation (NERC), and approved by the Commission, protect the public interest by ensuring a reliable and secure bulk power system. Enforcement ensures compliance with these standards and focuses primarily on violations resulting in actual harm, through the loss of load or other means. Enforcement also focuses on cases involving repeat violations of the Reliability Standards or violations that present a substantial risk to the bulk power system.

[4] The Federal Energy Regulatory Commission, Strategic Plan FY 2018-2022 (Sept. 2018) (Strategic Plan), *available at* https://www.ferc.gov/about/strat-docs/strat-plan.asp.

In FY2019, DOI staff opened 12 new investigations, while bringing 14 pending investigations to closure with no action. Additionally, during the fiscal year, staff negotiated two settlements of more than $14 million, which included $7.4 million in civil penalties and $7 million in disgorgement.[5] These Commission-approved settlements also included provisions requiring the subjects to enhance their compliance programs and periodically report back to Enforcement regarding the results of those compliance enhancements.

In FY2019, DAA completed 11 audits of public utility and natural gas companies covering a wide array of topics. The audits resulted in 76 findings of noncompliance, 286 recommendations for corrective action, the majority of which were implemented within six months, and directed $161.2 million in refunds and other recoveries. Additionally, during the fiscal year, DAA acted through the Chief Accountant's delegated authority on 120 accounting filings requesting approval of a proposed accounting treatment or financial reporting matter. Among its other work, DAA also assisted with numerous rate, pipeline certificate, merger and acquisition, and debt and security issuance proceedings before the Commission.

In FY2019, DAS surveillance reviewed numerous instances of potential misconduct, some of which resulted in DAS opening a surveillance inquiry, or an in-depth review of a market participant's conduct, to determine whether to recommend an investigation. During the fiscal year, natural gas surveillance screens produced approximately 7,629 screen trips which resulted in 20 natural gas surveillance inquiries and ultimately one referral to DOI for investigation. Electric surveillance screens produced approximately 369,230 screen trips which resulted in 23 electric surveillance inquiries and ultimately five referrals to DOI for investigation. In total, DAS closed 31 surveillance inquiries with no referral and, as of the end of the fiscal year, continued its analytic work on six. DAS also worked and provided analytical support on approximately 45 investigations with DOI.

DEMO continued its analysis of market fundamentals (including significant trends and developments) and enhancement of its analytical capabilities related to the ongoing eForms refresh project. As in prior years, DEMO presented its annual State of the Markets report assessing significant events in the energy markets during the previous year. This year's report also reviewed the development of US pipeline infrastructure and the rapid increase in the LNG export industry. Additionally, during the fiscal year, DEMO presented its Winter Energy Market Assessment and Summer Energy Market and Reliability Assessment. DEMO also assisted with over 40 docketed Commission proceedings where it evaluated the efficacy of certain regulatory policies in light of evolving energy markets. DEMO held one EQR user group meeting in FY2019 to conduct outreach with the filing community and to discuss potential system improvements and enhancements.

[5] A table of FY2019 Civil Penalty Enforcement Actions is attached as Appendix B to this report.

# DIVISION OF INVESTIGATIONS

## A. Overview

This section of the report provides details on DOI's current investigative processes and practices in order to give the energy industry, energy bar, and public added insight on investigations and to provide investigative subjects general guidance on what to expect during an investigation.

DOI staff conducts investigations of potential violations of the statutes, regulations, rules, orders, and tariffs administered by the Commission. DOI staff learns of potential violations from multiple sources, including referrals from other program offices within the Commission and other divisions within Enforcement; referrals from Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) in organized markets or their market monitoring units; referrals from other agencies; self-reports; calls to the Enforcement Hotline; whistleblowers; and information gathered in other investigations. After learning of a potential violation, DOI staff evaluates whether to open an investigation based on the factors outlined in the Commission's Revised Policy Statement on Enforcement.[6]

If, after gathering and reviewing relevant facts, DOI staff finds no violation or finds that a violation should not be subject to sanctions, DOI staff closes the investigation without action and informs the subject.[7] Most of DOI staff's investigations are closed without further action.[8] On the other hand, if DOI staff finds that a violation occurred that warrants sanctions, it provides the subject with its preliminary findings, either orally, in writing, or both. The subject then has the opportunity to respond to staff's preliminary findings with any additional information or defenses. This stage presents an important opportunity for the subject to supplement factual information or to point out its views and theories of the case. Where warranted, staff conducts additional fact-finding after reviewing a subject's response and may modify its findings based on the response and further fact-finding.

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[6] Revised Policy Statement, 123 FERC ¶ 61,156 at P 25.

[7] DOI closed seven investigations in FY2019 either because staff found no violation or because there was not enough evidence to conclude that a violation had occurred. In addition, DOI closed five investigations where it found violations but concluded that further proceedings were not warranted.

[8] In some circumstances, DOI finds that, while the investigation should terminate, there are broader market issues that may warrant attention. For example, the investigation may expose vague or ambiguous market rules that appear to undermine, distort, or otherwise inject uncertainty into market performance and participant obligations. To address these types of issues, Enforcement has a process whereby staff can share its concerns about existing tariffs, market rules, or business practice manuals with senior management in Enforcement and the Commission's Office of Energy Market Regulation (OEMR), Office of the General Counsel (OGC), and OEPI and explain how the issues may be resulting in poor or inefficient market outcomes.

If, after reviewing the subject's response to the preliminary findings and conducting supplemental fact-finding, DOI staff continues to conclude that violations occurred and that the violations warrant sanctions, it consults with OE management and then seeks authority from the Commission to enter into settlement negotiations with the subject.[9] This request for settlement authority describes the facts and law that led to staff's determination, recommends a range of settlement terms and penalty analysis under the Commission's Penalty Guidelines, and attaches the subject's preliminary-findings response(s). If the Commission grants settlement authority, staff seeks negotiated resolutions within the provided settlement authority range and with terms that will transparently inform the regulated industry about what conduct constitutes the violation. If an agreement is reached between Enforcement and the subject, it will be submitted to the Commission for approval. If approved, the Commission issues a public order that typically states why the settlement serves the public interest and attaches the settlement agreement. In FY2019, Enforcement staff resolved two investigations via settlements approved by the Commission: (1) a natural gas company's violation of its certificate of public convenience and necessity issued by the Commission under section 7(c) of the Natural Gas Act (NGA) (15 U.S.C. § 717f(c)) and Part 157 of the Commission's regulations (18 C.F.R. Part 157); and (2) an electric utility's violation of the Commission's Anti-Manipulation Rule (18 C.F.R. § 1c.2).[10] These settlements are described more fully below in DOI Section C.

If a settlement cannot be reached, and Enforcement intends to recommend issuance of an order to show cause (OSC), staff will provide the subject with notice and an opportunity to respond pursuant to section 1b.19 of the Commission's regulations. After reviewing this response, staff, if it continues to believe violations have occurred, drafts an Enforcement Staff Report and Recommendation, which includes its findings of fact and conclusions of law regarding the investigation, as well as its recommendation to issue an OSC. Following review and approval by OE management, this report and the subject's response to the section 1b.19 notice are then submitted to the Commission for a vote on the OSC. If the Commission concurs with staff's recommendation, it issues an OSC in a public docket directing the subject to explain why it did not commit a violation and why penalties and disgorgement are not warranted. The subject has an opportunity to respond to the OSC, and Enforcement staff may reply to the subject's response. The Commission's issuance of an OSC triggers the Commission's *ex parte* and separation of functions rules, because it initiates a contested on-the-record proceeding, with Enforcement and subjects as participants and the Commission as a neutral adjudicator.[11] The Commission therefore issues a public notice designating Enforcement as "non-decisional," with the exception of the specific Enforcement staff designated as "decisional," who had no prior involvement in the underlying investigation.

After considering the factual record and legal arguments submitted by the subject and Enforcement, the Commission issues a decision, which will take different forms depending on the

[9] Investigative subjects are free to raise and explore potential resolution of an investigation, including through settlement, at any time during an investigation.

[10] The Commission's regulations can be found at www.ecfr.gov.

[11] *See* 18 C.F.R. §§ 2201, 2202 (2019) (outlining the Commission's rules governing off-the-record communications and separation of functions). *See also* 5 U.S.C. § 554(d) (2014).

relevant statute. Under the NGA and under a default process under the Federal Power Act (FPA), the Commission can either rule on the pleadings or set the matter for hearing before an Administrative Law Judge (ALJ), assuming genuine issues of material fact exist. In these matters, the ALJ holds a hearing and issues an initial decision, which is followed by a final Commission decision that can be appealed to a U.S. Court of Appeals. Alternatively, if a civil penalty is proposed in an FPA matter, a subject can elect a process different from the ALJ route described above. A subject has 30 days following the OSC issuance in which to affirmatively elect a penalty assessment by the Commission followed by "review de novo" of the assessment before a district court. If such an election is made, the Commission follows its OSC paper hearing procedures but determines whether a violation occurred and, if so, assesses penalties through an order. If the subject does not pay the civil penalty within 60 days of the penalty assessment, the Commission is required by statute to file an action in district court for an order affirming the civil penalty. As of the end of FY2019, staff is litigating three such actions in federal court (all filed in previous years), seeking to enforce the Commission's combined assessment of more than $97.5 million in penalties and disgorgement. One NGA-related proceeding remains pending on rehearing before the Commission as of the end of the fiscal year.[12]

## B. Significant Matters

DOI staff spent substantial time in FY2019 preparing briefs, reports, and other public filings related to litigation in federal courts and administrative proceedings before the Commission, as well as on the Commission's joint inquiry with NERC into the January 17, 2018 cold weather event. In addition, during FY2019, staff requested that the Commission issue one new OSC.

DOI staff continues to represent the Commission in three litigation matters in United States District Courts. Currently pending at the Commission are two OSC proceedings and one NGA proceeding, in which the respondent's motion for rehearing is under consideration. A third OSC proceeding was terminated by the Commission upon the recommendation of Enforcement staff.

As of the end of FY2019, a total of approximately $76 million in civil penalties and $9 million in disgorgement of unjust profits, plus interest, remains pending in the federal court matters.

### 1. District Court Litigation

Over the past six years, Enforcement has filed seven enforcement actions in district courts across the country, including three that are still pending. In those proceedings, district courts have issued rulings to address a variety of procedural and substantive legal issues, including: (1) whether the Commission has five years from the date of the violation or from the date it assesses civil penalties for the violation to file an action in District Court to enforce the assessed penalties; (2) whether the Commission's civil actions seeking to enforce its penalty assessments should follow the Federal Rules of Civil Procedure; (3) the sufficiency of FERC's notice of fraud and deceptive conduct pleadings; (4) what constitutes individual culpability under the FPA; (5)

[12] For a more detailed discussion of the processes by which Enforcement conducts and concludes investigations, see Revised Policy Statement, 123 FERC ¶ 61,156 at PP 23-40.

particular activity that establishes manipulation; and (6) what evidence satisfies the scienter requirement under Section 222 of the FPA.

In FY2019, Enforcement staff continued litigating three matters in United States District Courts to enforce the Commission's penalty assessments under the FPA. Those District Court litigation matters were:

### *a) FERC v. Silkman, et al., No. 1:16cv00205 (D. Maine)*

On August 29, 2013, in Docket Nos. IN12-12-000 and IN12-13-000, the Commission issued orders assessing civil penalties in which it determined that Competitive Energy Services, LLC (CES), and Richard Silkman (CES's Managing Partner) (collectively, Respondents) violated the Commission's Anti-Manipulation Rule by engaging in a scheme related to ISO New England, Inc.'s (ISO-NE's) day-ahead load response program. Specifically, the Commission found that the Respondents had engaged in a scheme to fraudulently inflate energy load baselines for a resource and then offer load reductions against that inflated baseline. It assessed civil penalties of $7.5 million against CES and $1.25 million against Silkman and ordered disgorgement of $166,841, plus interest, from CES.

On December 2, 2013, Enforcement staff filed a petition in the United States District Court for the District of Massachusetts to enforce the penalty assessment order against Respondents. The Respondents filed a motion to dismiss the petition, which the District Court denied on April 11, 2016. In its order denying the Respondents' motion to dismiss, the Court specifically rejected the argument that the Commission was required to file its District Court action within five years of the violation (confirming that it has five years after the order assessing penalty to make such a filing), as well as the argument that the Commission cannot assess penalties against individuals for violating the Anti-Manipulation Rule. The Court then transferred the cases to the United States District Court for the District of Maine.

On January 26, 2017, after briefing and oral argument, the Maine District Court granted the Respondents' motion to treat the proceeding as an ordinary civil action subject to the Federal Rules of Civil Procedure. The parties participated in mediation before a magistrate judge in Portland, Maine on March 31, 2017, and were unable to reach an agreement on resolution. Fact discovery then commenced and was completed on November 30, 2017. Expert discovery was completed on April 30, 2018.

On January 29, 2018, upon agreement of the parties, the court ordered summary judgment briefing on the applicability of the statute of limitations. Briefing on the cross-motions for summary judgment was completed on April 20, 2018. On January 4, 2019, the Court issued an order finding that the Commission's action was not time-barred; therefore, the Commission's motion was granted and Respondents' motion was denied. Respondents subsequently sought certification of the Court's decision to the First Circuit Court of Appeals. Following briefing of the matter, the Court denied Respondents' motion for certification on June 26, 2019.

Trial in the matter is currently scheduled for April 27, 2020 in Bangor, Maine, with various pre-trial deadlines set for March and April 2020.

### *b) FERC v. Powhatan Energy Fund LLC, et al., No. 3:15-cv-00452 (E.D. Va.)*

On May 29, 2015, in Docket No. IN15-3-000, the Commission issued an order assessing civil penalties in which it determined that Powhatan Energy Fund, LLC (Powhatan), Houlian "Alan" Chen, HEEP Fund, Inc. (HEEP), and CU Fund, Inc. (CU) (collectively, Respondents) had violated the Commission's Anti-Manipulation Rule by engaging in fraudulent Up-To Congestion (UTC) trades in the PJM Interconnection, LLC (PJM) market during the summer of 2010. The Commission determined that the Respondents had engaged in trades to improperly collect certain market payments (called Marginal Loss Surplus Allocation, or "MLSA"). Specifically, the Commission found that Respondents had placed fraudulent round-trip trades (trades in opposite directions on the same paths, in the same volumes, during the same hours) that involved no economic risk and constituted wash trades. The Commission assessed civil penalties of $16.8 million against Powhatan, $1 million against Chen, $1.92 million against HEEP, and $10.08 million against CU and ordered disgorgement of unjust profits, plus interest, in the amounts of $3,465,108 from Powhatan, $173,100 from HEEP, and $1,080,576 from CU.

On July 31, 2015, Enforcement staff filed a petition in the United States District Court for the Eastern District of Virginia to enforce the Commission's Order. Following briefing requested by the Court on the de novo review procedures required by section 31(d)(3) of the FPA, the Court directed FERC to re-file its petition or file an amended complaint. The Commission filed an amended complaint on January 29, 2018, and Respondents moved to dismiss in part on February 28, 2018, based on statute of limitations grounds. On September 24, 2018, the Court found that the Commission had met the statute of limitations, but authorized Respondents to seek interlocutory appeal. On October 4, 2018, Respondents petitioned the United States Court of Appeals for the Fourth Circuit to review the order, and the Commission did not oppose the appeal. The Fourth Circuit granted the petition for review on November 5, 2018. Following briefing, the Fourth Circuit has scheduled oral argument for December 11, 2019.

The District Court case has been stayed pending resolution of the appeal.

### *c) FERC v. Coaltrain Energy L.P, et al., No. 2:16-cv-00732 (S.D. Ohio)*

On May 27, 2016, in Docket No. IN16-4-000, the Commission issued an order assessing civil penalties against Coaltrain Energy, L.P. (Coaltrain), its owners, Peter Jones and Shawn Sheehan, and Robert Jones, Jeff Miller, and Jack Wells, who developed and implemented the relevant trading strategy (collectively, Respondents). The Commission found that the Respondents violated the Commission's Anti-Manipulation Rule by engaging in fraudulent UTC trades in the PJM market during the summer of 2010. In so doing, it determined that Respondents' "over-collected loss" or "OCL" trading strategy, which sought to capture payments by placing large volumes of UTC trades between trading points with negligible price separation, was fraudulent and manipulative. The Commission found that the Respondents' OCL trading strategy involved three types of trades to improperly collect MLSA payments: (1) trading between export and import points (SOUTHIMP and SOUTHEXP) that had identical prices; (2) trading between export and import points (NCMPAIMP and NCMPAEXP) that had *de minimis* price differences; and (3) trading along various other paths and combinations of paths with minimal price differences. In each type of trade, the purpose was not to profit from spread changes, but instead to increase transmission volumes in order to collect MLSA payments.

The Commission also found that the Respondents violated section 35.41(b) of the Commission's regulations by making false and misleading statements and material omissions in Coaltrain's communications with Enforcement staff during the investigation in order to conceal the existence of relevant documents. The Commission ordered Coaltrain, jointly and severally with its co-owners Peter Jones and Shawn Sheehan, to disgorge $4,121,894 in unjust profits, plus interest. It also imposed civil penalties of $26 million on Coaltrain, $5 million each on Peter Jones and Shawn Sheehan, $1 million on Robert Jones, and $500,000 each on Jeff Miller and Jack Wells.

On July 27, 2016, Enforcement staff filed a petition in the United States District Court for the Southern District of Ohio to enforce the Commission's Order. The Respondents filed motions to dismiss or transfer, which were denied by order of the Court on March 30, 2018. Discovery commenced shortly thereafter, and is currently scheduled to run into November 2019. Initial expert reports were exchanged by both sides on September 19, 2019; rebuttal expert reports are scheduled to be exchanged by November 18, 2019. Motions for summary judgment are scheduled to be filed in early 2020. As yet, there is no trial date.

## 2. Administrative Proceedings at the Commission

### *a) Vitol Inc. and Federico Corteggiano, Docket No. IN14-4-000*

On July 10, 2019, the Commission issued an OSC to Vitol Inc. and its individual trader Federico Corteggiano (collectively, Respondents) directing them to show cause why they should not be found to have violated the Commission's Anti-Manipulation Rule and section 222 of the FPA by selling physical power at a loss in October and November 2013 in the California Independent System Operator's (CAISO) day-ahead market for the purpose of eliminating congestion costs that they expected to cause losses on Vitol's Congestion Revenue Rights (CRR) positions. The OSC also directed Respondents to show cause why disgorgement and civil penalties should not be assessed in the following amounts: disgorgement of $1,227,143, plus interest, from Vitol; a civil penalty of $6,000,000 against Vitol; and a civil penalty of $800,000 from Corteggiano.

After the parties submitted various procedural pleadings, Respondents filed their answers to the OSC on August 23, 2019. Enforcement staff filed its reply on September 20, 2019. Subsequent to the close of FY2019, on October 25, 2019, the Commission issued an order assessing civil penalties against Vitol and Corteggiano, finding that they engaged in a scheme to sell physical power, not to try to profit based on supply and demand fundamentals, but, rather, to eliminate congestion that they anticipated would cause losses on their CRR position. The Commission assessed a penalty of $1,515,738 against Vitol and $1,000,000 against Corteggiano. The Commission also ordered Vitol to disgorge $1,227,143 in unjust profits. Vitol and Corteggiano have sixty days from the date of the Commission's order to pay the penalty assessments. If they fail to pay, the Commission is required by statute to file an action in district court for an order affirming the civil penalties.

### *b) Footprint Power LLC, Footprint Power Salem Harbor Operations LLC, Docket No. IN18-7-000*

On June 18, 2018, the Commission issued an OSC directing Footprint Power LLC and Footprint Power Salem Harbor Operations (collectively, Respondents) to show cause why they should not be found to have violated the Transmission, Markets and Services Tariff (Tariff) of ISO-NE and sections 35.41(a) and (b) of the Commission's regulations. Enforcement Staff alleged violations by Respondents for: (1) submitting false and misleading supply offers for Footprint's capacity resource - Unit 4 of Footprint's multi-unit Salem Harbor Power Plant in Salem, Massachusetts; (2) failing to report the fuel status and related operational status of the capacity resource to ISO-NE in June and July of 2013; (3) submitting false and misleading supply offers in violation of ISO-NE's Tariff; and (4) submitting false or misleading information and/or omitting material information regarding Salem Harbor and Unit 4 in their communications with ISO-NE. Additionally, the OSC directed Respondents to show cause why disgorgement and civil penalties should not be assessed in the following amounts: disgorgement of $2,049,571, which reflected the capacity payments received during the relevant period, and a civil penalty of $4,200,000.

On August 2, 2018, Respondents filed their Answer to the OSC denying they committed the violations and raising a new argument regarding Unit 4's start-up requirements and how that affected the unit's ability to provide capacity during a certain portion of the relevant period. While the start-up requirements of Unit 4 were referenced at times during the investigation, the import of those start-up requirements as a specific defense to the four tariff provisions at issue had not been apparent before Respondents raised this argument. Upon review, staff concluded that the supply offers on those days did not constitute a violation.

On September 19, 2018, Enforcement staff filed a Reply to Respondents' Answer, wherein staff acknowledged that it found merit in the new defense presented by Respondents. Based on that conclusion, and the resulting reduction in scope of the case for the remainder of the relevant period, staff recommended that the Commission vacate its OSC and that no penalties be assessed against Respondents.

The Commission agreed with Enforcement staff's assessment and recommendation. On February 25, 2019, the Commission issued an order terminating the OSC proceeding.

### *c) Total Gas & Power North America, Inc., et al.*, Docket No. IN12-17-000

On April 28, 2016, the Commission issued an OSC directing Total Gas & Power North America, Inc. (TGPNA), Aaron Hall, and Therese Tran (collectively, Respondents) to show cause why they should not be found to have violated section 4A of the NGA and the Commission's Anti-Manipulation Rule by engaging in a scheme to manipulate the price of natural gas at four locations in the southwest United States between June 2009 and June 2012. The OSC further directed TGPNA's ultimate parent company, Total, S.A. (Total), and TGPNA's affiliate, Total Gas & Power, Ltd. (TGPL), to show cause why they should not be held liable for the Respondents' conduct and held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Finally, the OSC directed the Respondents to show cause why disgorgement and civil penalties should not be

assessed in the following amounts: $9,180,000 in disgorgement and $213,600,000 in civil penalties against TGPNA, Total, and TGPL, jointly and severally; $1,000,000 civil penalty against Hall (jointly and severally with TGPNA, Total, and TGPL), and $2,000,000 civil penalty against Tran (jointly and severally with TGPNA, Total, and TGPL).

In advance of the OSC, on January 27, 2016, Respondents filed a lawsuit in the United States District Court for the Western District of Texas, challenging (among other things) the Commission's authority to assess penalties for violations of the NGA.[13] After the case was transferred to the United States District Court for the Southern District of Texas, that court rejected the Respondents' challenge on multiple grounds. The Respondents appealed that dismissal to the U.S. Court of Appeals for the Fifth Circuit on September 26, 2016, which on June 8, 2017 affirmed the dismissal. The Respondents subsequently sought rehearing in the Fifth Circuit *en banc*, which was denied on August 8, 2017. The Respondents then petitioned the United States Supreme Court for certiorari, which the Court denied on June 18, 2018. The matter is pending before the Commission.

### *d) BP America Inc., et al., Docket No. IN13-15-000*

On August 5, 2013, the Commission issued an OSC to several BP entities directing BP to show cause why the Commission should not: (1) find that BP violated the Anti-Manipulation Rule and section 4A of the NGA by manipulating the next-day, fixed-price natural gas market at Houston Ship Channel from September 2008 to November 2008; (2) impose a civil penalty in the amount of $28,000,000; and (3) require BP to disgorge $800,000 of unjust profits.

On August 13, 2015, Judge Carmen Cintron issued her Initial Decision finding that BP violated the Anti-Manipulation Rule and section 4A of the NGA. On July 11, 2016, the Commission issued an Order affirming Judge Cintron's Initial Decision and ordered BP to pay $20,160,000 in civil penalties and disgorge unjust profits in the amount of $207,169 to the Low Income Home Energy Assistance Program (LIHEAP) of Texas for the benefit of its energy consumers. The Commission also denied BP's motion for rehearing of the Commission's initial order setting the case for hearing. On August 10, 2016, BP moved for rehearing of the Commission's July 11, 2016, decision.

On September 7, 2016, BP moved for modification of the portion of the Commission's Order directing BP to pay the disgorgement to the Texas LIHEAP, alleging that Texas LIHEAP communicated to BP that it was unable to receive such a payment. The Commission responded with two orders. First, on September 8, 2016, the Commission granted rehearing for the limited purpose of further consideration of the matters raised by BP in its motion for rehearing of the July 11, 2016, decision. Second, on September 12, 2016, the Commission issued an order staying the payment directive of the disgorgement order until the Commission issues an order on BP's request for rehearing. On September 9, 2016, BP separately filed a Petition for Review in the U.S. Court of Appeals for the Fifth Circuit only on the procedural issues ripe for appeal.

[13] Additional details about this District Court matter and subsequent appeals can be found in the 2018 Staff Report on Enforcement (Docket No. AD07-13-012), *available at* https://www.ferc.gov/legal/staff-reports/2018/11-15-18-enforcement.pdf.

On December 11, 2017, BP filed a motion with the Commission for rehearing or to dismiss based on two recent court decisions, *FERC v. Barclays Bank PLC*, 2017 WL 4340258 (E.D. Cal. Sept. 29, 2017) and *Kokesh v. SEC,* 137 S.Ct. 1635 (2017). BP contends that *Barclays* holds that a Commission order to show cause does not initiate a "proceeding" under the applicable federal statute of limitations, 28 U.S.C. § 2462, and therefore, this case was not timely brought and should be dismissed. BP also argues that it cannot be ordered to repay its unjust profits because the same statute of limitations applies to actions for disgorgement under *Kokesh*. OE staff's response was filed on January 25, 2018. This matter is pending before the Commission.

### 3. Inquiry into South-Central United States Cold Weather Event of January 17, 2018

On January 17, 2018, a large area of the south central region of the United States experienced unusually cold weather, which had been predicted five days earlier. The below-average temperatures resulted in a total of 183 individual generating units within the Reliability Coordinator (RC) footprints of the Southwest Power Pool, Inc. (SPP), the Midcontinent Independent System Operator, Inc. (MISO), the Tennessee Valley Authority (TVA), and Southern Company's Southeastern RC experiencing either an outage, a derate, or a failure to start between January 15 and January 19, 2018. The unexpected generation outages caused a capacity emergency in MISO South and widespread transmission system constraints across all or part of nine states. In September 2018, the Commission announced the formation of a joint inquiry with NERC and four Regional Reliability Entities to determine the causes of the event and make recommendations to prevent such events in the future. Enforcement staff, including individuals from DOI, were part of the FERC team that conducted an inquiry into the matter. Staff reviewed entity data and conducted interviews to determine the causes of the generation losses and to develop recommendations.

The inquiry team issued its report on July 18, 2019.[14] FERC and NERC staff found that at least 44 percent of the generation losses were directly or indirectly related to the extreme cold, and 70 to 74 percent of the units that experienced an outage, derate, or failure to start were gas-powered. Despite guidance since 2011 on the need to prepare generating units for winter weather, approximately one-third of the generating units involved did not have plans to do so. The system in MISO South was so stressed on January 17, 2018 that the loss of one additional large generating unit would have required MISO to shed firm load to restore its reserves while shedding additional firm load to maintain voltage within limits.

The report made 13 recommendations to prevent similar future events. The recommendations were shared with the affected entities and applicable trade groups for their consideration and feedback before being finalized. The report repeated a recommendation from a 2011 cold weather inquiry for NERC to draft a new or revised Reliability Standard to address the issue of generation owners failing to prepare for winter weather. NERC has accepted a Standards Authorization

[14] FERC and NERC Staff Report, The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (July 2019), *available at* https://www.ferc.gov/legal/staff-reports/2019/07-18-19-ferc-nerc-report.pdf.

Request, which begins the process to potentially approve a new Reliability Standard. Additional recommendations included: (1) RCs performing voltage stability analysis; (2) transmission planners performing additional studies to better forecast constrained conditions; (3) MISO South improving its five-to-three-day-ahead load forecasts and communicating when it is relying on non-firm transmission to serve its firm load; and (4) transmission operators using summer and winter ratings where possible.

## C. Settlements

In FY2019, the Commission approved two settlement agreements between Enforcement and subjects to resolve pending matters. The settlements totaled $7.4 million in civil penalties and disgorgement of $7 million. Since 2007, Enforcement has negotiated settlements totaling approximately $783.4 million in civil penalties and approximately $518 million in disgorgements.

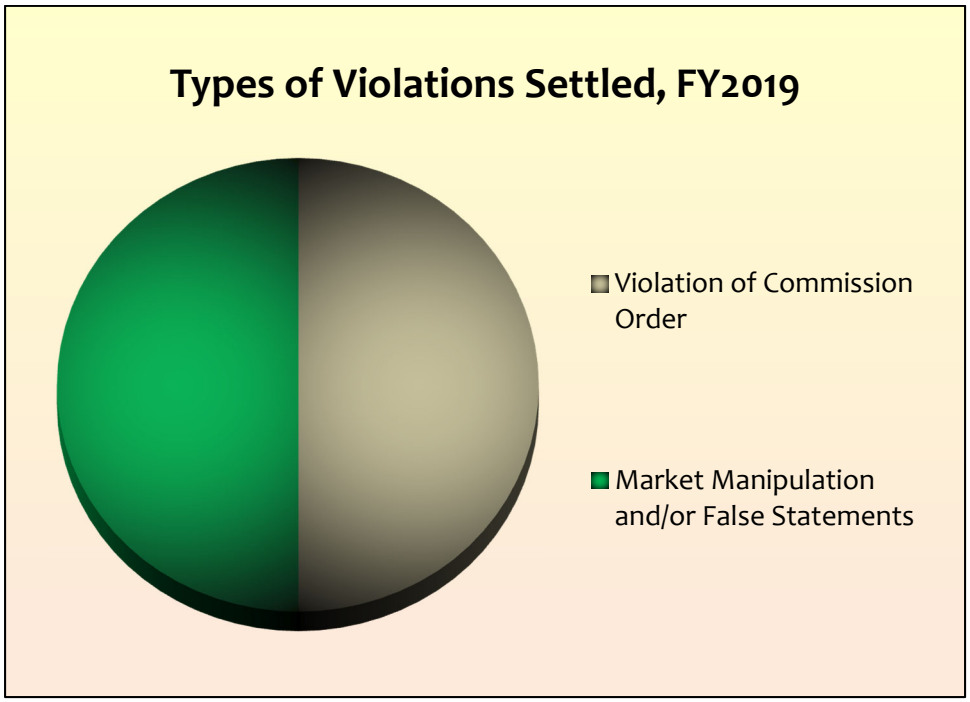
In 2010, the Commission issued revised Penalty Guidelines.[15] Under the Penalty Guidelines, an organization's civil penalty can vary significantly depending on the amount of market harm caused by the violation, the amount of unjust profits, an organization's efforts to remedy the violation, and other culpability factors, such as senior-level personnel involvement, prior history of violations, compliance programs, self-reporting of the violation, acceptance of responsibility, and cooperation with Enforcement's investigation. For example, under the Penalty Guidelines, an organization's culpability score can be reduced to zero through favorable culpability factors, lowering the base penalty by as much as 95 percent.[16]

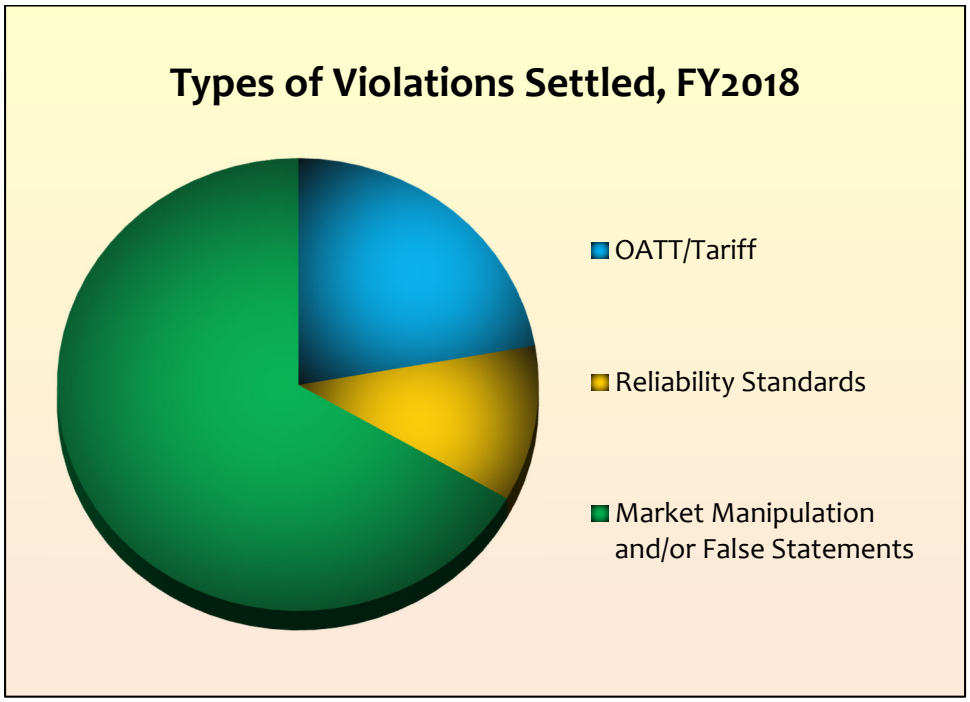
In FY2019, the Commission approved settlement agreements that resolved investigations concerning violations of the Commission's Anti-Manipulation Rule as well as violations of a Commission Order issued pursuant to the NGA's pipeline certification requirements, and associated Commission regulations.

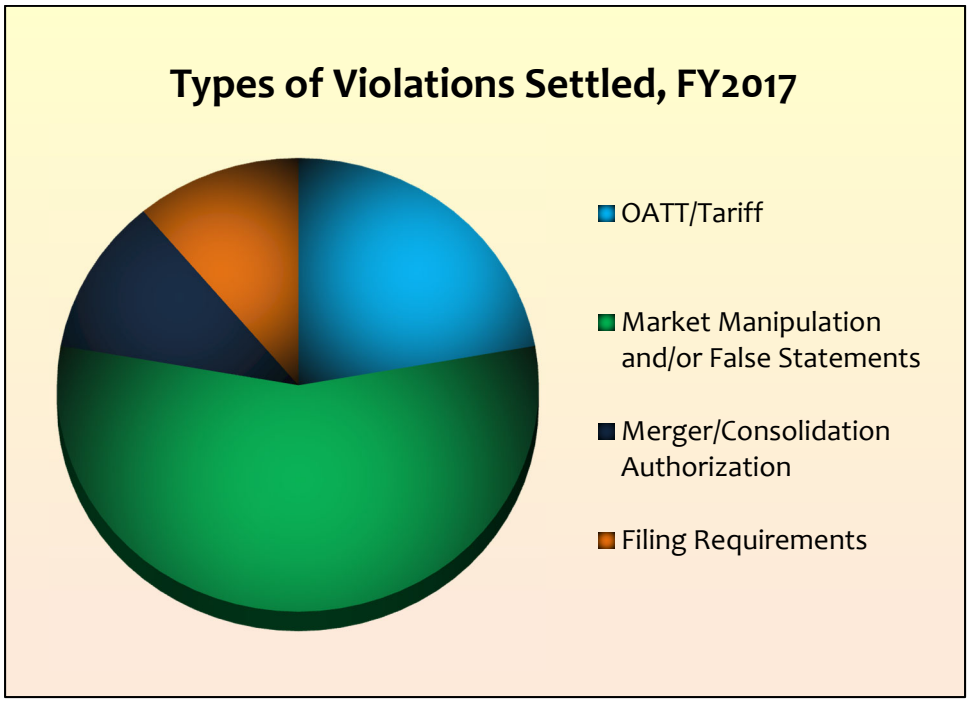
The charts below illustrate the types of violations settled in the last five fiscal years, Fiscal Years 2015-2019. Some settlements concerned multiple types of violations.

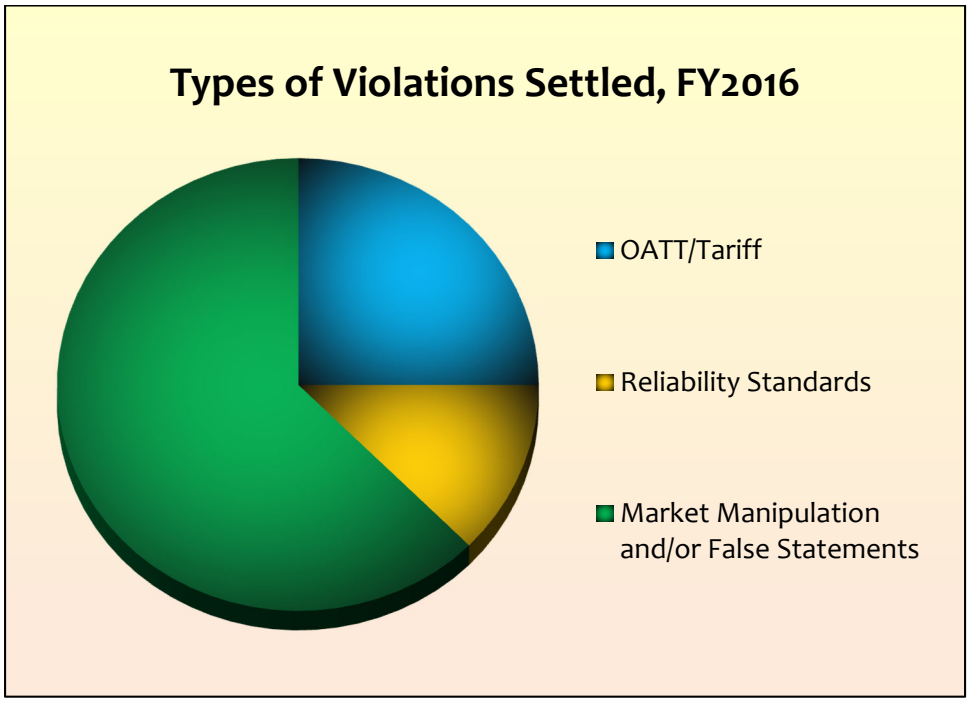
[15] *Revised Policy Statement on Penalty Guidelines*, 132 FERC ¶ 61,216 (2010) (Revised Penalty Guidelines), *available at* https://www.ferc.gov/whats-new/comm-meet/2010/091610/M-1.pdf.

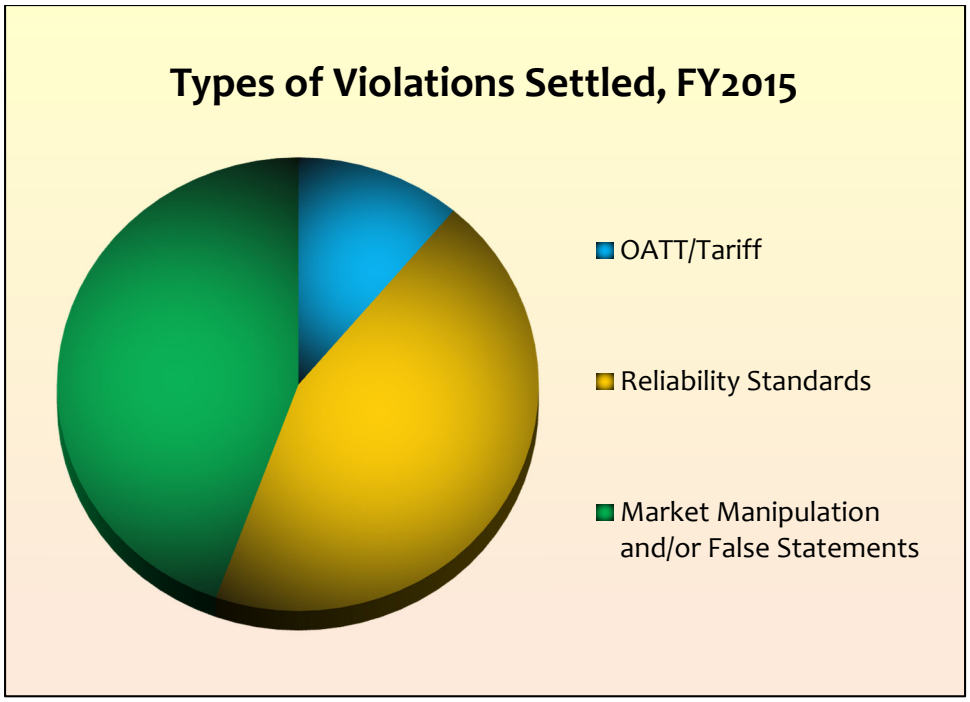
[16] *Id.* P 109.


Types of Violations Settled, FY2019
Violation of Commission Order
Market Manipulation and/or False Statements


Types of Violations Settled, FY2018
OATT/Tariff
Reliability Standards
Market Manipulation and/or False Statements


Types of Violations Settled, FY2017
OATT/Tariff
Market Manipulation and/or False Statements
Merger/Consolidation Authorization
Filing Requirements


Types of Violations Settled, FY2016
OATT/Tariff
Reliability Standards
Market Manipulation and/or False Statements




The Commission approved the following settlement agreements in FY2019:

### Algonquin Gas Transmission, LLC, Docket No. IN19-2-000

On January 7, 2019, the Commission issued an order approving the settlement of Enforcement's investigation of Algonquin Gas Transmission, LLC (Algonquin) regarding the company's obligations under its Commission-issued Certificate of Public Convenience and Necessity (Project Certificate). Enforcement's investigation found that Algonquin violated its Project Certificate, issued under section 7(c) of the NGA (15 U.S.C. § 717f(c)) and Part 157 of the Commission's regulations (18 C.F.R. Part 157), when it entered a wetland area with construction equipment in an attempt to retrieve a broken drill stem in August 2016 before obtaining a required variance. Enforcement found that Algonquin's work in the wetland area failed to comply with the Commission's Project Certificate issued to Algonquin. Under the terms of the settlement, Algonquin admitted to the facts, but neither admitted nor denied the violations. Algonquin agreed to pay a civil penalty of $400,000, and to submit semi-annual environmental compliance monitoring reports for one year, with a potential one-year extension at Enforcement's discretion.

### Dominion Energy Virginia, Docket No. IN19-3-000

On May 3, 2019, the Commission issued an order approving the settlement of Enforcement's investigation of Virginia Electric and Power Company (d/b/a Dominion Energy Virginia (DEV)) relating to its receipt of lost opportunity cost credits (LOCs) in the PJM market. Enforcement's investigation found that DEV violated the Commission's Anti-Manipulation Rule by targeting and maximizing its receipt of LOCs paid to combustion turbine units that cleared the day-ahead market and were not dispatched in the real-time market, during the period April 2010 to March 2011. Staff determined that DEV engaged in a strategy that sought to obtain more day-ahead commitments by discounting the units' incremental energy offers, and at the same time, sought to

reduce the chance the units would be dispatched in the real-time market by substantially increasing the start-up values in their day-ahead offers. Staff found that DEV offered its units in this manner not based on supply and demand fundamentals, but, rather, for the purpose of targeting and obtaining LOCs. Under the terms of the settlement, DEV stipulated to the facts, but neither admitted nor denied the violations. DEV agreed to pay a civil penalty of $7 million and disgorgement to PJM of $7 million, and also to submit an annual compliance monitoring report, with a potential one-year extension at Enforcement's discretion.

## D. Self-Reports

Over the previous five fiscal years (Fiscal Years 2015-19), staff received approximately 574 self-reports. The vast majority of those self-reports were concluded without further enforcement action because there was no material harm (or the reporting companies already had agreed to remedy any harms) and the companies had taken appropriate corrective measures (including appropriate curative filings), both to remedy the violation and to avoid future violations through enhancements to their compliance programs.

### 1. Statistics on Self-Reports

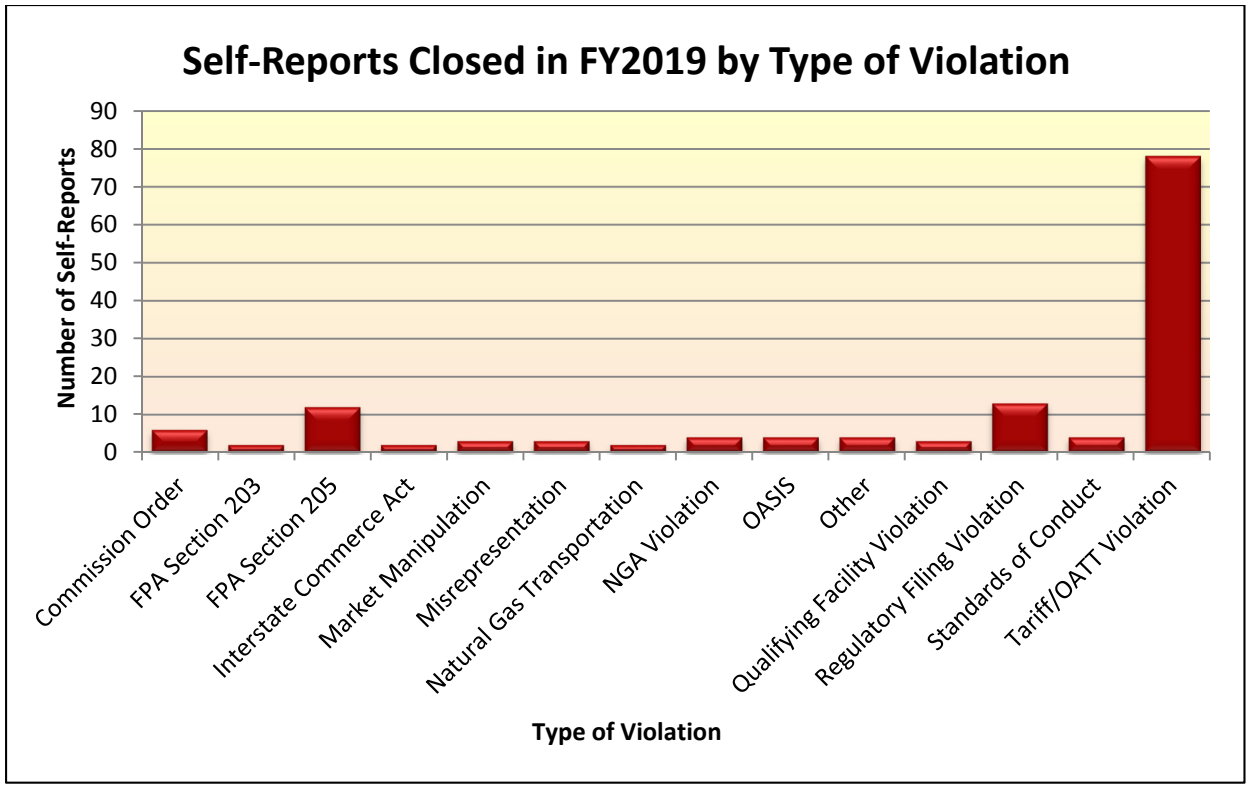
In FY2019, staff received 149 new self-reports from a variety of market participants, including public utilities, natural gas companies, generators, and ISOs/RTOs. The majority of these self-reports (91) were from ISOs/RTOs and involved relatively minor violations of tariff provisions. Two of the self-reports received were the source for two investigations opened this fiscal year. Staff closed 130 self-reports in FY2019, 13 of which were carried over from the previous fiscal year. Of the self-reports received in FY2019, 32 remained pending at the end of the fiscal year.

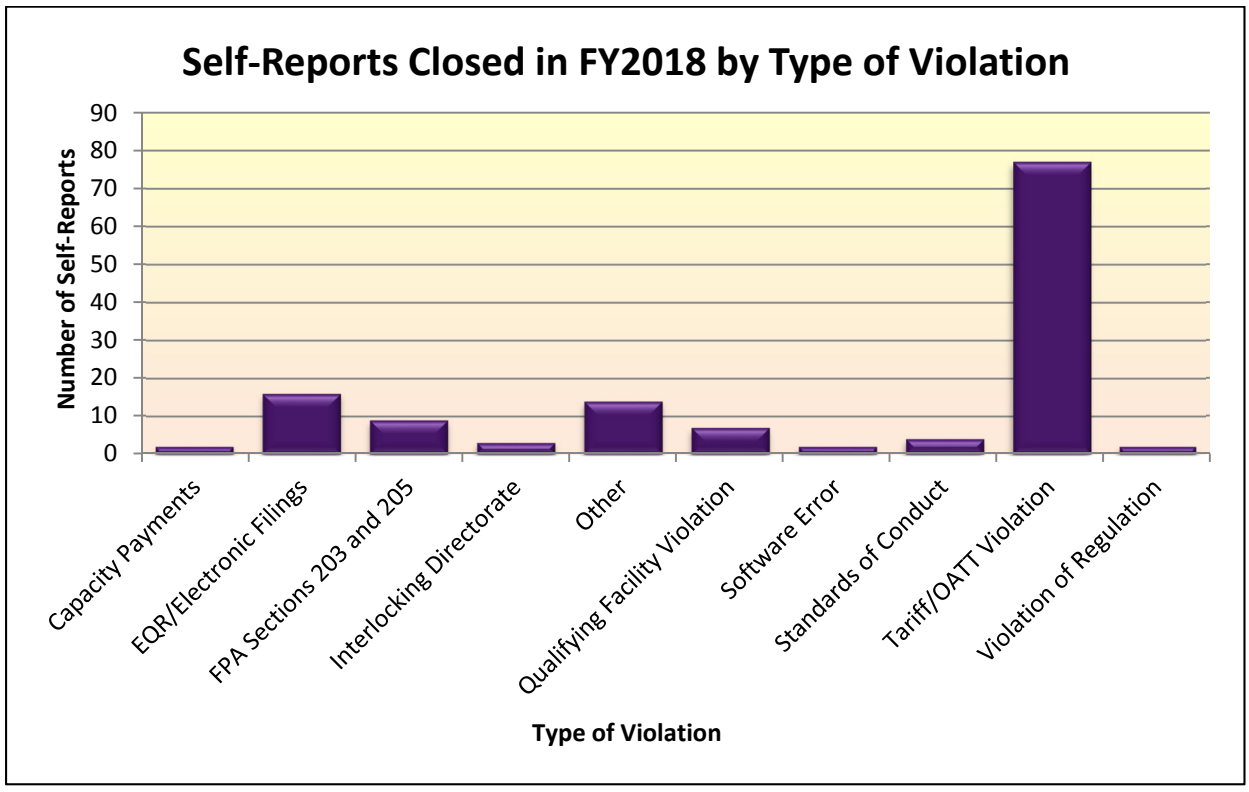
The Penalty Guidelines emphasize the importance of self-reporting by providing credit that can significantly mitigate penalties if a self-report is made.[17] Staff continues to encourage the submission of self-reports and views self-reports as showing a company's commitment to compliance.

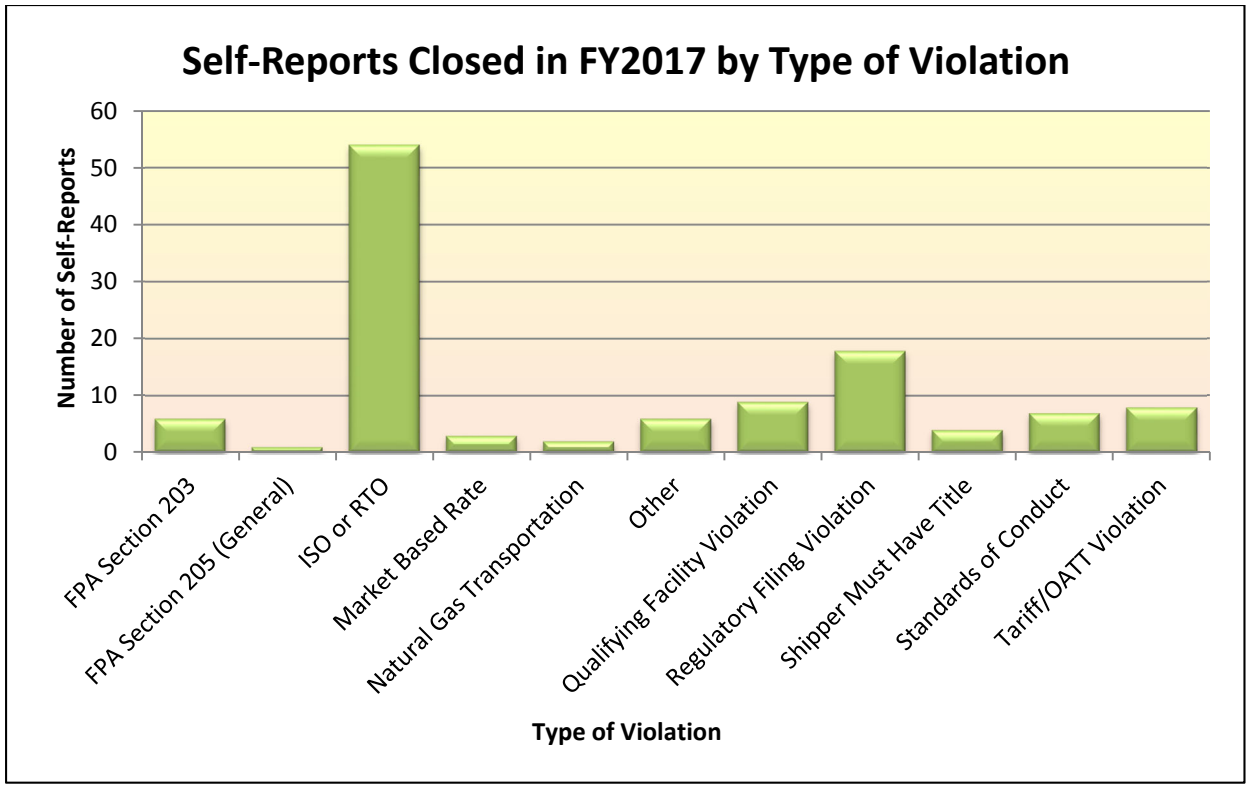
The following charts depict the types of violations for which staff received self-reports from Fiscal Years 2015 through 2019.[18] Some self-reports include more than one type of violation.

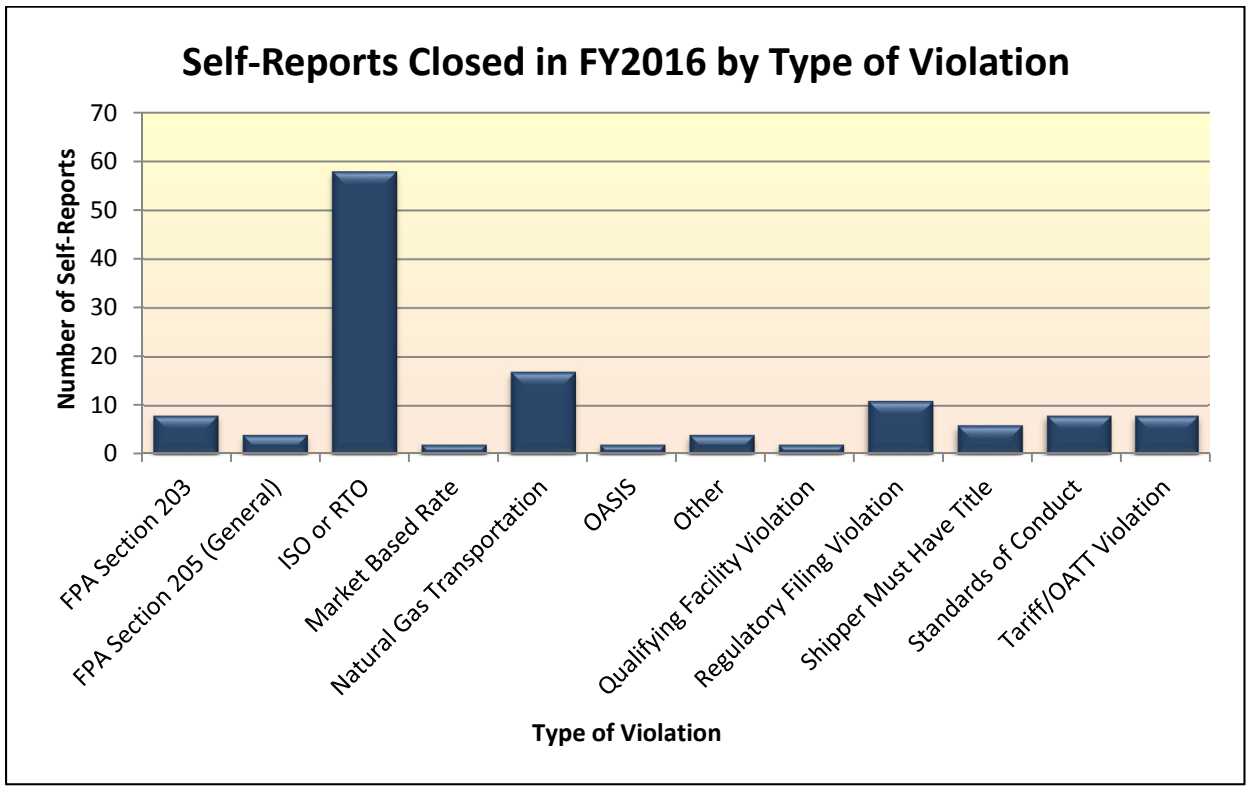
[17] Revised Penalty Guidelines, 132 FERC ¶ 61,216 at P 127.

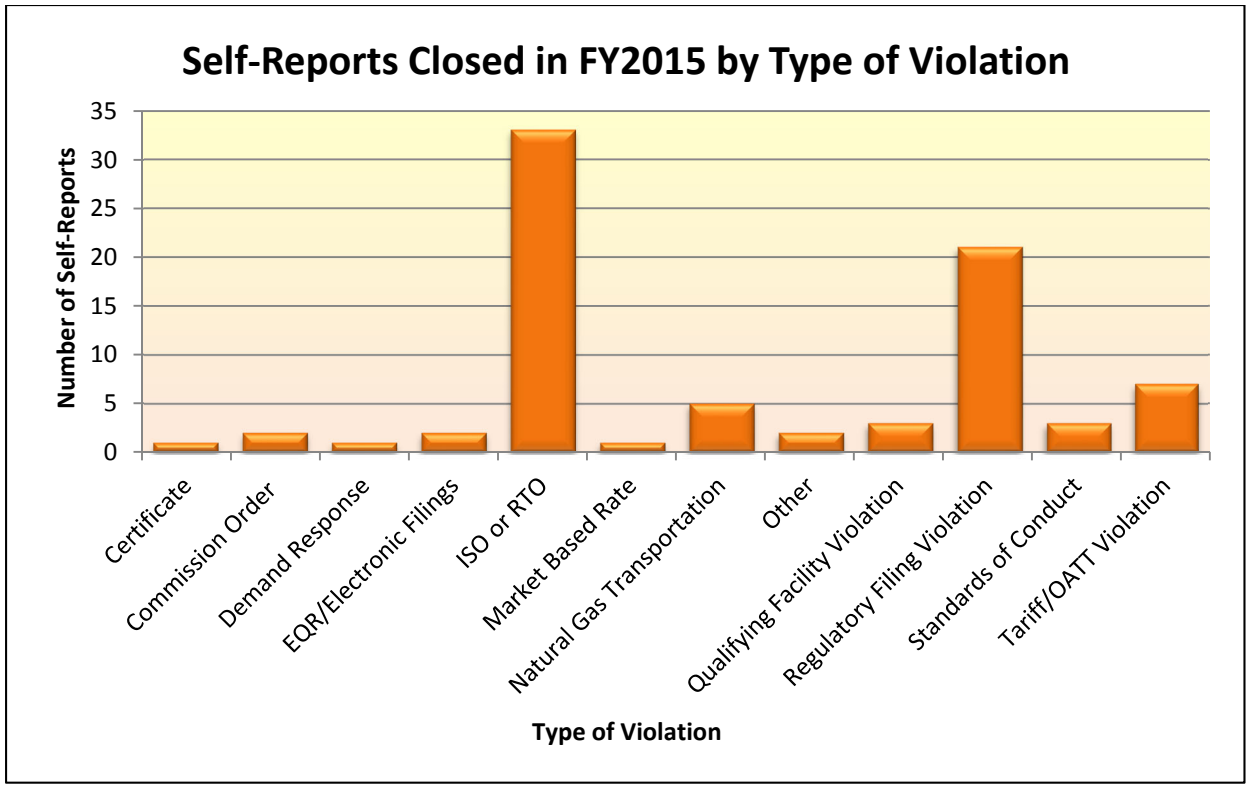
[18] Consistent with the FY2018 Annual Report, the FY2019 Self Reports Closed chart includes the substantive violation reported from an ISO/RTO, and replaces the ISO/RTO category used in previous years.


Self-Reports Closed in FY2019 by Type of Violation
Number of Self-Reports
90
80
70
60
50
40
30
20
10
0
Commission Order
FPA Section 203
FPA Section 205
Interstate Commerce Act
Market Manipulation
Misrepresentation
Natural Gas Transportation
NGA Violation
OASIS
Other
Qualifying Facility Violation
Regulatory Filing Violation
Standards of Conduct
Tariff/OATT Violation
Type of Violation


Self-Reports Closed in FY2018 by Type of Violation
Number of Self-Reports
90
80
70
60
50
40
30
20
10
0
Capacity Payments
EQR/Electronic Filings
FPA Sections 203 and 205
Interlocking Directorate
Other
Qualifying Facility Violation
Software Error
Standards of Conduct
Tariff/OATT Violation
Violation of Regulation
Type of Violation


Self-Reports Closed in FY2017 by Type of Violation
Number of Self-Reports
60
50
40
30
20
10
0
FPA Section 203
FPA Section 205 (General)
ISO or RTO
Market Based Rate
Natural Gas Transportation
Other
Qualifying Facility Violation
Regulatory Filing Violation
Shipper Must Have Title
Standards of Conduct
Tariff/OATT Violation
Type of Violation


Self-Reports Closed in FY2016 by Type of Violation
Number of Self-Reports
70
60
50
40
30
20
10
0
FPA Section 203
FPA Section 205 (General)
ISO or RTO
Market Based Rate
Natural Gas Transportation
OASIS
Other
Qualifying Facility Violation
Regulatory Filing Violation
Shipper Must Have Title
Standards of Conduct
Tariff/OATT Violation
Type of Violation




## 2. Illustrative Self-Reports Closed with No Action

In a continuing effort to promote transparency while encouraging the compliance efforts of regulated entities, Enforcement presents the following illustrative examples of self-reports that DOI staff closed in FY2019 without conversion to an investigation. In determining whether to close a self-report or open an investigation, staff considers the factors set forth in the Commission's Revised Policy Statement on Enforcement.[19] As examples, in FY2019 several ISOs/RTOs and market participants reported minor tariff and reporting violations, at least two market participants reported potential market manipulation, three public utilities reported standards of conduct violations, four natural gas companies reported pipeline certificate violations, and several companies reported notice and regulatory filing violations resulting from inadvertent oversight or changes in ownership. The illustrative summaries below are intended to provide guidance to the public and to regulated entities as to why staff chose not to pursue an investigation or enforcement action, while preserving the non-public nature of the self-reports.

**FPA Section 203 Violation (Disposition of Assets) and Late Change in Status Filing.** A public utility self-reported that one of its subsidiaries had failed to seek Commission approval before selling its ownership interest in one of its generating facilities in violation of section 203(a)(1)(A) of the FPA. Certain financing characteristics of the sale resulted in a change in the subsidiary's status for purposes of retaining its market-based rate authority, and it also failed to timely report this change of status, in violation of section 35.42 of the Commission's regulations. To remediate the violations, the subsidiary late-filed the required documents to obtain Commission approval,

[19] Revised Policy Statement, 123 FERC ¶ 61,156 at P 25.

and submitted the outstanding change in status filings. The public utility also implemented various compliance improvements to ensure similar noncompliance will not occur in the future, and conducted additional employee training. For these reasons, and because the violation was isolated, inadvertent, had little practical effect, and caused no economic harm, staff closed this self-report without further action.

**FPA Section 205 Violation (Market Based Rate Authorization).** A generation company self-reported that it made wholesale sales without market based rate authorization (MBR) in violation of section 205 of the FPA. The company had sold power to a buyer pursuant to a Power Purchase Agreement (PPA) that complied with the Public Utility Regulatory Policies Act (PURPA) and the Commission's regulations. When that agreement ended the company continued to sell to the same buyer, after executing a new PPA. These sales violated section 205 of the FPA because the seller did not have MBR authority for sales under the new PPA. Upon discovery, the company promptly filed for MBR authority, which the Commission granted. The company was obligated to make time value refunds for the unauthorized sales it made between the end of the first PPA and the Commission's grant of MBR authority. Because the company made this refund and took steps to prevent future recurrence of this violation, staff closed this self-report without further action.

**FPA Section 205 Violation and Regulatory Filing Violation (Failure to File Certain Agreements and EQR).** An energy services company self-reported that it failed to file certain agreements in violation of section 205 of the FPA and various Commission filing requirements outlined in Part 35 of the Commission's regulations. Specifically, the company failed to: (1) timely file transmission-related agreements; (2) timely file a Facilities Reimbursement Agreement and Phase Two Permitting and Engineering Agreement; (3) timely file a Transmission Asset Lease Agreement; and (4) report agreements in its EQR for certain reporting periods. The company identified these agreements after undertaking a comprehensive review of its records and took the necessary steps to come into full compliance by making the required filings. In a majority of cases, the services provided under these agreements were provided at no charge and to the extent there was a charge, it was only a pass-through of the company's costs on a dollar-for-dollar basis (i.e., no margin was collected). As such, no economic harm resulted from the late filings. For these reasons, staff closed this self-report without further action.

**Interstate Commerce Act Violation.** An oil pipeline self-reported that it inadvertently disclosed confidential shipper information in violation of section 15(13) of the Interstate Commerce Act, which prohibits common carrier product pipelines from disclosing information relating to the "nature, kind, quantity, destination, consignee, or routing" of the products being transported without the shipper's consent. *See* 49 U.S.C. app. § 15(13) (1988). A scheduler at the pipeline sent an email with the schedule of a third-party shipper's movements to the wrong distribution list. Within five minutes, the scheduler was notified of the error and sent an email stating "Please discard." The incident was reported within the company, ultimately to the company's legal department. The company investigated and determined the incident was inadvertent, the scheduler followed up with each recipient to confirm the email was discarded and not shared, the substance of the email was very limited and therefore presented no harm to the shipper or gain to the email recipients, and the shipper informed the company that the barrels were ultimately sold to other parties and not shipped. For these reasons, and because the company took steps to prevent future violations, staff closed this self-report without further action.

**Market Manipulation (Material Misrepresentations).** A curtailment service provider operating within an ISO/RTO self-reported a potential violation of the Commission's Anti-Manipulation Rule. Some of its sales managers and employees made false statements to several of its demand resource customers in connection with the customers' demand response contracts for two recent delivery years. Upon learning of the false statements, the curtailment service provider initiated an internal investigation, issued sanctions to its sales staff (including terminating the sales managers and several of the senior sales staff), notified customers and paid them refunds, and updated the relevant portions of its training for sales staff. Because the curtailment service provider took timely and effective remedial measures to address the potential violations and prevent reoccurrence, staff closed this self-report without further action.

**Market Manipulation (Scheme to Defraud).** An energy trading company self-reported a potential violation of the Commission's Anti-Manipulation Rule. A former trader, while employed with the company, made virtual trades in an ISO/RTO based on recommendations and trading strategies received from another company that the trader eventually went to work for. Some of these trades were placed on days when the other company was also placing trades in the same ISO/RTO. The company reported the trading because of concerns about possible collusive or manipulative behavior. Staff analyzed the trading and did not find evidence of collusion, manipulation, or other violations of market rules. For these reasons, staff closed this self-report without further action.

**Misrepresentation to a Jurisdictional Transmission Provider.** A company that provides energy marketing services to public utility companies and municipalities self-reported that one of its traders made a misrepresentation to a jurisdictional transmission provider in violation of section 35.41(b) of the Commission's regulations. After incorrectly tagging an energy sale for one of its member-clients to another region, the trader attempted to correct the error by finding an alternative buyer. In the process of doing so, the trader told a transmission provider that the transaction needed to flow 15 MW of power for reliability reasons to avoid a unit trip, and provided the same incorrect information to a reliability coordinator. The trader appeared to have engaged in the conduct independent of any direction from its member-client. In reviewing the self-report, staff determined that the company did not qualify as a Seller under section 35.41(b) of the Commission's regulations. For this reason, and because the company has active compliance and training programs that it has committed to review and improve, and has taken steps to prevent the conduct from recurring, staff closed this self-report without further action.

**Natural Gas Transportation Violation (Shipper Must Have Title Violation).** A company (Company 1) self-reported that it had violated the Commission's shipper-must-have-title (SMHT) requirement by transporting natural gas it owned on interstate pipelines using capacity reserved for a second Company (Company 2). For seven years Company 1 and Company 2 entered into repeated long-term capacity releases so Company 1 could ship its gas using Company 2's capacity while satisfying the Commission's SMHT requirement. However, when the last long-term capacity release expired, the person who served as the capacity manager had left employment at Company 1 and no one at either company took note of the expiration of the long-term release. Accordingly, Company 1 continued to use the capacity for an additional eight years without renewing the long-term release. Upon discovering the violations, based on a question from the pipeline owner, Company 1 and Company 2 immediately entered into a short-term and then a long-term capacity release. Company 1 also hired outside counsel to develop procedures for tracking

its capacity and gas contracts. Counsel also developed and conducted training on the SMHT requirement and created a manual for employees to consult. Because of these prompt mitigation measures, and because the violations were inadvertent, and, despite their duration, caused no harm, staff closed this self-report without further action.

**NGA Section 1(c) Violation (Hinshaw Exemption).** A natural gas pipeline self-reported a potential violation of section 1(c) of the NGA, which exempts pipelines from Commission regulation provided they satisfy certain eligibility criteria, including that the pipeline operates entirely within a single state (Hinshaw Exemption). The pipeline learned through ongoing compliance audits that its intrastate facilities included several limited border crossings. Upon learning of the potential crossings, the company immediately performed a thorough investigation to determine the existence and extent of the border crossings, physically eliminated some of the crossings, and made appropriate filings at the Commission to preserve its Hinshaw exemption. For these reasons, and because the violations were inadvertent and resulted in no market harm, staff closed this self-report without further action.

**NGA Section 7(b) Violation (Abandonment).** A natural gas pipeline self-reported that it abandoned two different jurisdictional facilities without Commission authorization in violation of section 7(b) of the NGA. After discovering the violations, the pipeline filed for, and received, Commission approval to formally abandon the facilities. For this reason, and because the violations were inadvertent and resulted in no market harm, staff closed this self-report without further action.

**OASIS Posting Violation and Tariff/OATT Violation.** A public utility self-reported its failure to post certain information to its Open Access Same-Time Information System (OASIS) platform in violation of section 37.6 of the Commission's regulations and the company's Open Access Transmission Tariff. The utility had failed to: (1) post narratives explaining its Available Transfer Capacity (ATC) reductions; and (2) timely complete notifications of impacts resulting from a transmission outage. The first issue stemmed from the disablement of an automated functionality that initiates the posting of ATC narratives within its OASIS software platform. The second issue resulted from utility personnel failing to recognize the full impact that the outage of a transformer owned by another utility would have on one of its transmission lines. Staff determined that the posting and outage issues were inadvertent and caused no harm to other entities. For these reasons, and because the utility implemented remedial actions to prevent future compliance issues, staff closed this self-report without further action.

**Qualifying Facility Violation (Unauthorized Power Sales).** The owner of a cogeneration plant self-reported its failure to self-certify this project as a Qualifying Facility (QF) before it began making wholesale power sales in violation of section 205 of the FPA. Although section 292.601 of the Commission's regulations affords QFs under 20 MW, such as the cogeneration plant, an exemption from section 205 of the FPA, the Commission's regulations require owners of such QFs to either file a notice of self-certification or apply for a Commission certification in order to obtain QF status pursuant to 18 C.F.R § 292.207 (QF Filing Requirement). To remedy this violation, the owner submitted a FERC Form No. 556 to certify the project as a QF. No refunds were due because the project owner had not yet collected any revenues for the sales that occurred. Because

the violation was inadvertent and resulted in no economic harm, staff closed this self-report without further action.

**Regulatory Filing Violation (Electric Quarterly Reports).** A public utility self-reported several errors in its EQRs in violation of section 35.10b of the Commission's regulations (EQR Filing Requirement). Pursuant to the EQR Filing Requirement, each public utility and non-public utility with more than a *de minimis* market presence must file an updated EQR covering jurisdictional services it provides. EQRs are required to be filed within 30 days after the end of each quarter. The public utility identified multiple reporting errors in its EQRs between 2015 and 2019. These errors included: (1) reporting a quarterly cumulative capacity payment when it should have reported at least three individual capacity transactions with unique rate and volume information; (2) failing to report various energy and capacity transactions; and (3) reporting one transaction that should have been reported in the EQR of an affiliate. The reporting errors resulted from a misunderstanding of the specific filing requirements and from a change in ownership. The utility worked with staff to cure its reporting deficiencies and implemented procedures and training to limit the likelihood that additional violations will occur. For these reasons, staff closed this self-report without further action.

**Regulatory Filing Violation (FERC Form No. 552).** A small gas exploration and development company self-reported that it had failed to file FERC Form No. 552 in violation of section 260.401 of the Commission's regulations. Pursuant to this regulation, unless otherwise exempted, each natural gas market participant, i.e. any buyer or seller that engaged in physical natural gas transactions the previous calendar year, must prepare and file with the Commission a Form No. 552, which addresses its natural gas transactions. The form must be filed by May 1 for the previous calendar year. After acquiring a gas marketing unit from another company, the gas exploration company had failed to file FERC Form No. 552 the following two years. The company worked with staff to ensure that all missing Form No. 552s were filed. For this reason, and because the violations were inadvertent and resulted in no economic harm, staff closed this self-report without further action.

**Regulatory Filing Violation (FERC Form No. 566).** The owner of a generation facility self-reported that it failed to file FERC Form No. 566, listing its 20 largest retail customers, for three calendar years in violation of section 46.3 of the Commission's regulations. The company had never had any retail customers, but was still required to file the form. This oversight resulted from the company's failure to transfer the FERC Form No. 566 reporting responsibility after the responsible employee left the company. At staff's request, the company filed the three FERC Form No. 566s out-of-time. Staff determined that the violation would not recur because the company is now an Exempt Wholesale Generator (EWG), and thus exempt from the filing requirement. For this reason, and because the violations were inadvertent and resulted in no harm, staff closed this self-report without further action.

**Regulatory Filing Violation (Failure to Update Tariff).** A FERC jurisdictional oil pipeline self-reported that it failed to update its tariff to reflect third-party agreements with one of its shippers in violation of section 341.3(b)(7) of the Commission's regulations. Pursuant to this regulation, a regulated oil pipeline may not charge rates for its services other than those properly filed with the Commission. The pipeline's violation occurred when it failed to incorporate the agreements it

made with the shipper into its tariff at the time they were executed. The pipeline also failed to update its tariff to reflect rates adjusted by these agreements in 2016, 2017, and 2018. The pipeline explained that the agreements were made to provide financial assistance to its anchor and only committed shipper. Staff determined that the violation did not permanently impact any other shipper and the only party directly impacted by the rate in question, the pipeline's anchor shipper, benefited under the rate change. For these reasons, staff closed this self-report without further action.

**Regulatory Filing Violation (Interlocking Directorate).** A public utility self-reported a violation of the Commission's requirements regarding Interlocking Directorates (18 C.F.R. Part 45) for failing to: (1) report the appointment of a new director; and (2) give notice of the contemporaneous resignation of the prior director. The utility's failure to make the requisite filings was an oversight due to the fact that the new director shadowed the prior director for some period of time, and the person responsible for the filing, who subsequently left the utility, failed to make the filing when the actual transition took place. The utility worked diligently with staff to cure the reporting deficiencies and implemented procedures and training to limit the likelihood additional violations will occur. For these reasons, staff closed this self-report without further action.

**Regulatory Filing Violation (Late Change in Status – Category Seller Designation).** The owner of several wind projects self-reported that after purchasing the projects it failed to timely change its ownership status for the projects, as required by section 35.42 of the Commission's regulations. The owner remedied the violation by making the late change in status filings and taking steps to prevent recurrence of this violation in the future. The only harm caused by this delay impacted the owner, who was unable to take advantage of certain exemptions associated with its status. For these reasons, and because the violation was unintentional, staff closed this self-report without further action.

**Standards of Conduct (No Conduit Rule).** A public utility self-reported that, over a period of up to six years, certain transmission function information stored on intranet websites was inadvertently available to all employees, including marketing function employees, in violation of section 358.6 of the Commission's regulations (Standards of Conduct - No Conduit Rule). The problem resulted from a software setting which allowed employees to give any other company employee access to documents stored in management folders, one of which contained a substantial number of transmission-related documents. The utility learned of the violation following a corporate compliance training and, within 3 days, revoked access to the documents and began an investigation which included interviews of all marketing function employees with access to the transmission materials, all of whom stated that they did not access the transmission-related information. In addition, the utility reviewed other document management systems and verified they did not contain the same flaws. Staff determined that the utility had conducted a thorough internal investigation of the matter and implemented changes to prevent recurrence. Although the duration of the violations was substantial, they were inadvertent and it was not clear that any harm resulted. For these reasons, staff closed this self-report without further action.

**Standards of Conduct (Transparency Rule).** A transmission provider self-reported that it failed to timely update the job title of a transmission function employee on OASIS, in violation of section 358.7 of the Commission's Regulations (Standards of Conduct – Transparency Rule). The

company updated the information on OASIS 12 days after the 7-day time frame required by the Standards of Conduct. Upon discovery, a senior compliance analyst discussed this issue with the responsible employee and performed individual training to ensure future compliance with the Standards of Conduct. Further, the company implemented a new control whereby IT provides it with a weekly report to monitor whether any personnel changes create any Standards of Conduct obligations. Staff determined that the company acted quickly to remedy the situation and prevent recurrence. For these reasons, and because no harm resulted, staff closed this self-report without further action.

**Tariff/OATT Violation (Electric).** An investor-owned utility self-reported its failure to provide historical fuel data to two ISO/RTOs' market monitors for certain months in 2017 and 2018 in violation of the ISO/RTOs' Tariffs. Regarding the violation in one ISO/RTO, the company explained that the responsible employee twice encountered technical issues when attempting to upload fuel data to the ISO/RTO market monitor's software system. The employee contacted the ISO/RTO market monitor for assistance, but continued to have technical issues loading the data. Regarding the violation in the other ISO/RTO, the company explained that its failure to provide fuel data resulted from employee turnover. By February 2019, the company provided the market monitors with the missing historical fuel data. The company has implemented process improvements to avoid future data submission errors and to enhance its overall compliance efforts. Those process improvements include increasing the number of responsible staff, implementing auto-reminders for submission deadlines and confirmations for receipt of submissions, and conducting annual training on data submittals. For these reasons, and because of the technical issues encountered by the employee when attempting to load fuel data, staff closed this self-report without further action.

**Tariff/OATT Violation (Electric).** An investor-owned utility self-reported that it inadvertently failed to undesignate a network resource prior to an off-system sale for two early morning hours, in violation of its OATT. The company had previously arranged for a day-ahead off-system sale, scheduled power flow from the appropriate unit (Unit), purchased firm transmission, and undesignated the Unit as a network resource as required. Before the power flow was scheduled to occur, the Unit tripped offline. Company employees took steps to change all firm sales from the Unit to other units, not realizing that a firm off-system sale was scheduled, and that sourcing the off-system power from a unit that had not been undesignated as a network resource violated its OATT. Upon discovery, employees began completing a request to undesignate the new unit but did not complete the request until after power had sourced from the network-designated unit for two hours. Staff determined that no transmission customers were impacted and no revenues were inappropriately collected. For these reasons, and because the violation was inadvertent and the company acted quickly to address it, staff closed this self-report without further action.

**Tariff/OATT Violation (Oil Pipeline).** An oil pipeline self-reported two potential violations of its Commission-approved tariff: (1) it did not post its tariff on its website; and (2) it charged its only customer more than the Commission-authorized rate. Regarding the first issue, the company did not know how long the tariff was missing from its website, but it remedied the violation by posting it. The violation occurred because the company was not aware of its obligation to post the tariff. Its customer was provided a copy of the tariff as an attachment to its contract. Regarding the second issue, the company determined that, due to an employee's misunderstanding, it

increased its rate without filing a tariff revision with the Commission. Upon discovery, the company reduced its rates to the amount in its tariff, began an investigation, and refunded the overpayments with interest (approximately $19,000). Staff determined that these violations resulted in little harm to its customer, market participants who may have wanted to become customers, or the Commission's regulatory process. For these reasons, and because the violations were inadvertent and were remedied by the company, staff closed this self-report without further action.

**Tariff/OATT Violation (ISOs/RTOs).** Multiple ISOs/RTOs in organized markets self-reported relatively minor violations of their tariffs, resulting from either software errors or human errors. Such errors included: small miscalculations of the reserves that resources could provide; miscalculating uplift payments; failing to take required actions against assets in default of financial assurance obligations; failing to take required actions against market participants who had been assessed a penalty for submitting inaccurate fuel cost information; the incorrect inclusion or exclusion of costs in a manner inconsistent with the tariff; software errors that created the potential for incorrect market participant compensation; the inadvertent temporary grant of access to confidential market participant information; software errors that resulted in inaccurate modeling inputs; and failure to post certain links on its website pursuant to its tariff and North American Energy Standards Board (NAESB) standards. The ISOs/RTOs also reported certain other potential errors stemming from ambiguity in their tariffs or mistakes in implementing tariff provisions. Examples included the calculation of make-whole payments for resources with minimum run times spanning multiple days and committing generators with a "Reliability" status for reasons other than an emergency or local reliability issue. In all such instances, the violations were inadvertent, resulted in minimal harm, and were promptly and effectively remedied to mitigate the harm and prevent future violations. Accordingly, staff closed these self-reports without further action.

**Violation of Commission Order (Pipeline Certificate).** A natural gas pipeline company self-reported that its construction of a storage area access road to support a pipeline replacement project impacted a wetland in violation of the blanket certificate authority it had been granted by prior Commission order. The company promptly and effectively worked with government officials to complete a formal plan to remove the access-road fill material and developed a detailed wetland restoration and monitoring project. Staff determined that restoration was an appropriate and viable response to the company's violation. For this reason, staff closed this self-report with no action but required that the company report this issue in its FERC Form No. 537 (Annual Certificate Report).

## E. Investigations

In FY2019, DOI staff opened 12 new investigations, as compared with 24 investigations opened in FY2018. The majority of these investigations arose from referrals by ISO/RTO market monitors and Enforcement's DAS. Additional investigations stemmed from referrals by ISOs/RTOs, self-reports, and from the Enforcement Hotline. In addition to cases closed through settlement, staff closed 14 investigations in FY2019 without further action, as compared to 23 investigations closed without further action in FY2018. In addition to closing these investigations during the fiscal year, DOI staff closed several MMU Referrals following inquiries into and

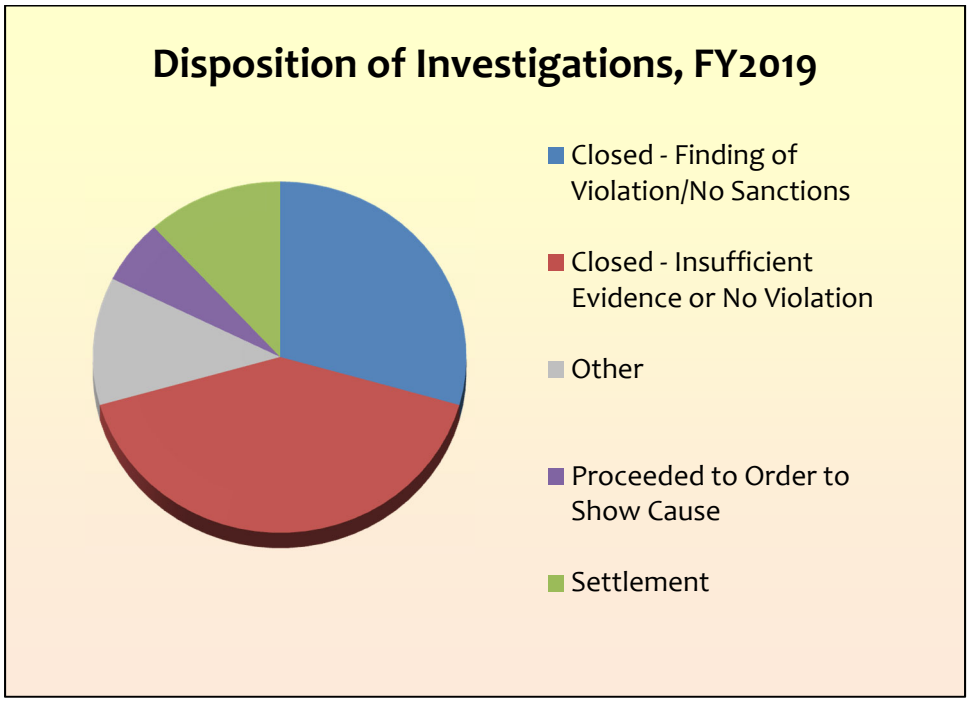
analyses of the referred conduct and alleged violations. These matters, discussed in DOI Section F below, were closed without being converted into investigations.

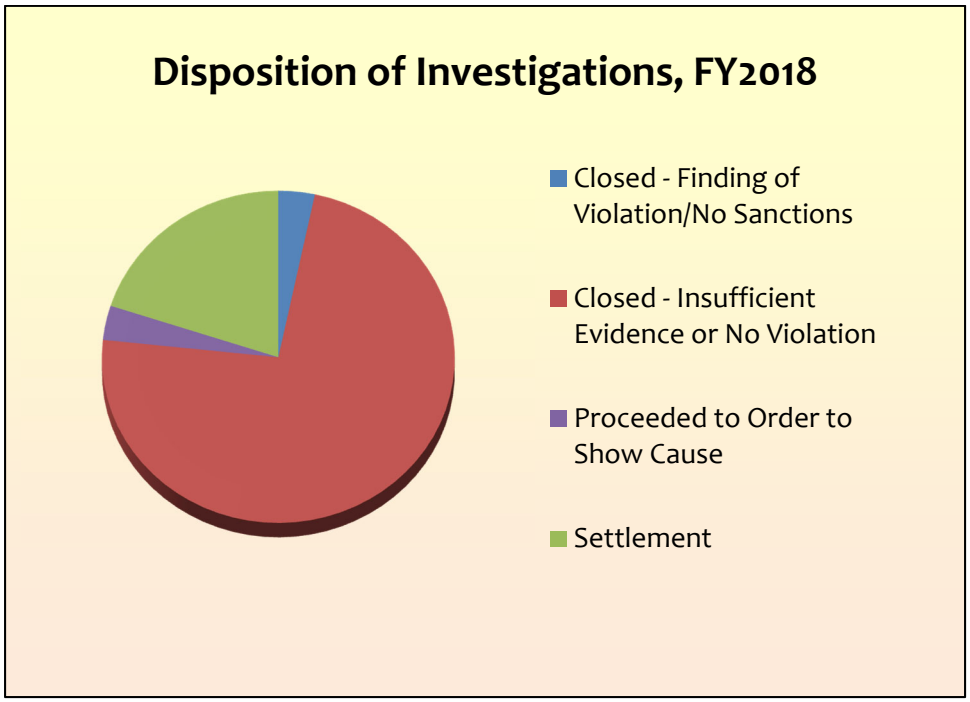
## 1. Statistics on Investigations

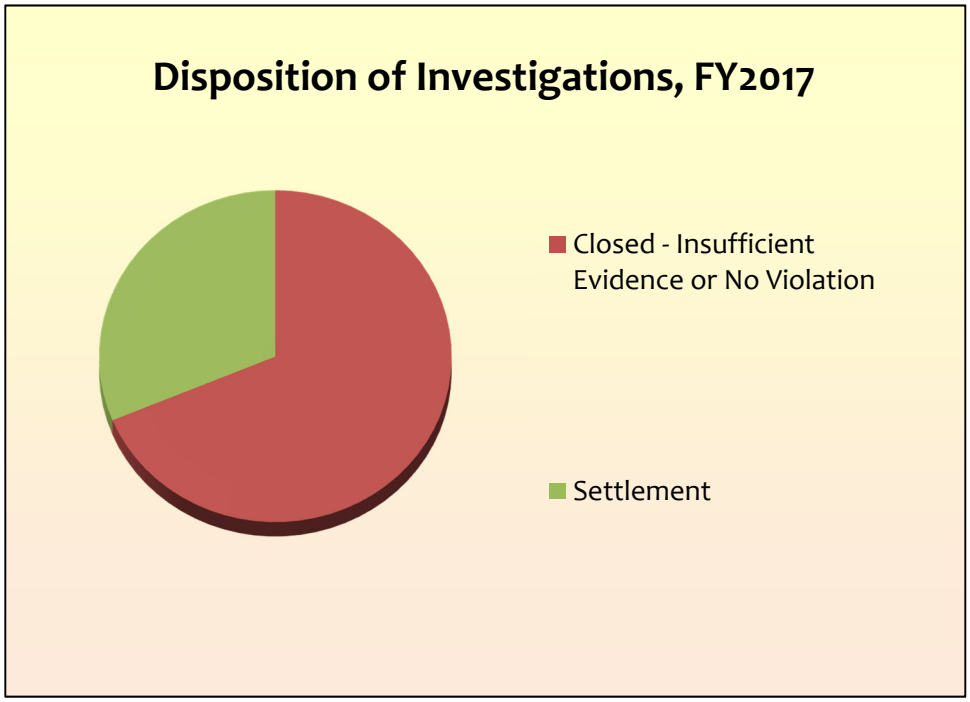
Of the 12 investigations staff opened this fiscal year (some of which involved more than one type of potential violation or multiple subjects), nine involved potential market manipulation, seven involved potential tariff violations, six involved misrepresentations prohibited by the Commission's market behavior rules, and two involved regulatory filing violations. The 12 investigations involved a wide range of additional issues, including safety concerns, Critical Infrastructure Protection standards, demand response, and failure to update the prices in a gas tariff.

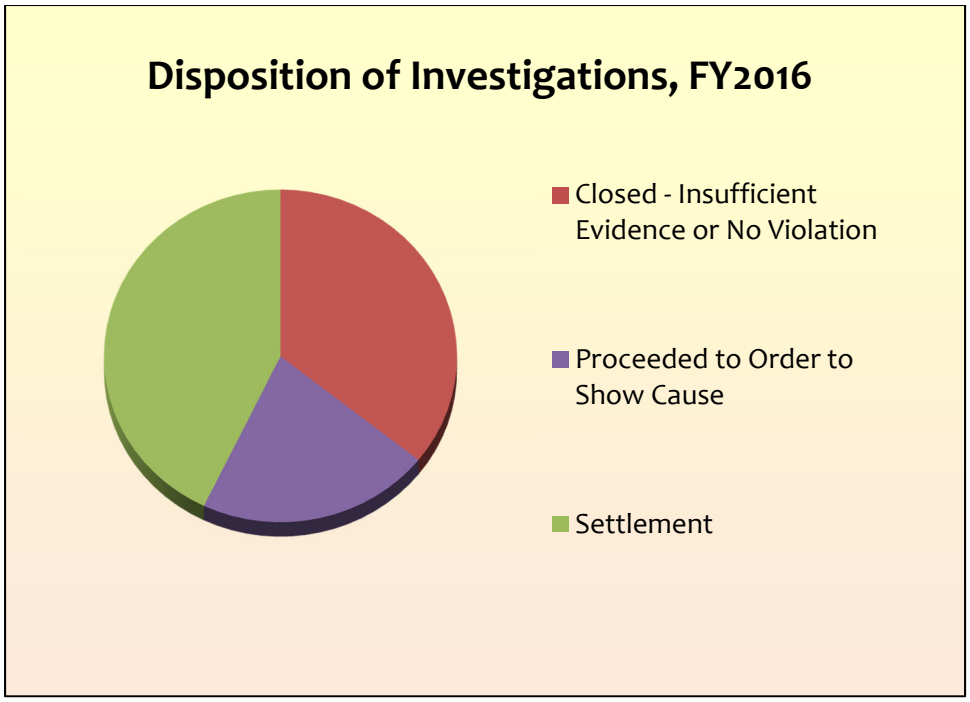
DOI staff closed 14 investigations in FY2019. Of the closed investigations, seven were closed without further action because staff concluded that the evidence did not support finding a violation. In five other investigations, a violation was found but staff did not pursue a sanction. DOI also closed two investigations following Commission Orders relevant to the matters being investigated. The 14 closings were in addition to the two investigations closed pursuant to settlements that staff reached with subjects. The Commission-approved settlements in these investigations are summarized above in DOI Section C and listed in Appendix B. Illustrative examples of investigations closed without enforcement action are discussed below.

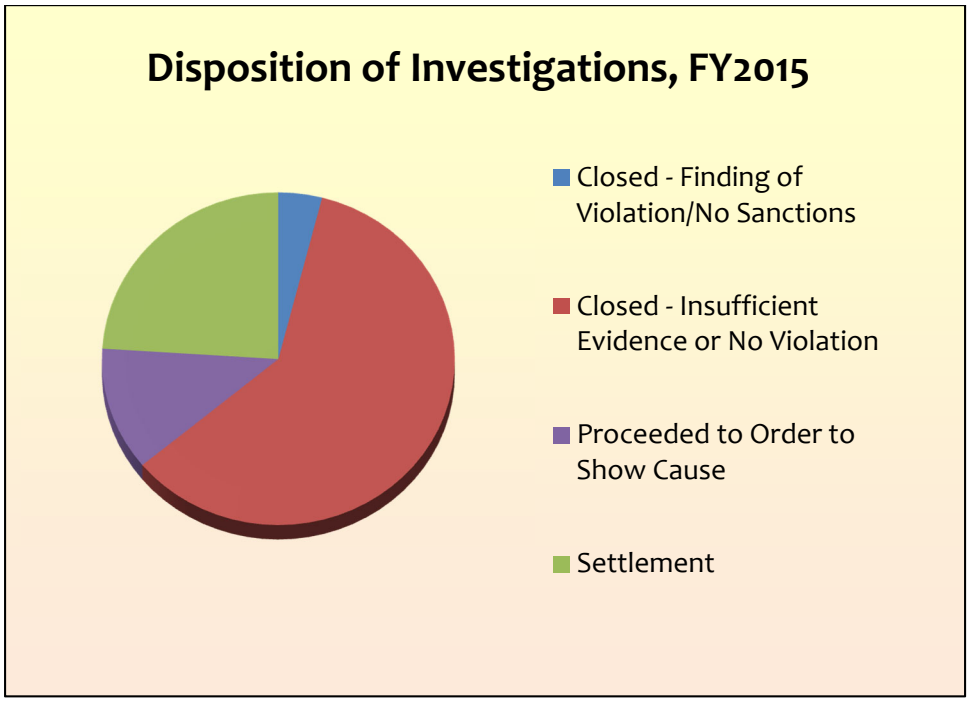
The following charts show the year-by-year disposition of investigations that closed over the past five years (FY2015-2019) and the aggregate disposition of investigations that closed over the previous decade from fiscal years 2009 through 2019.

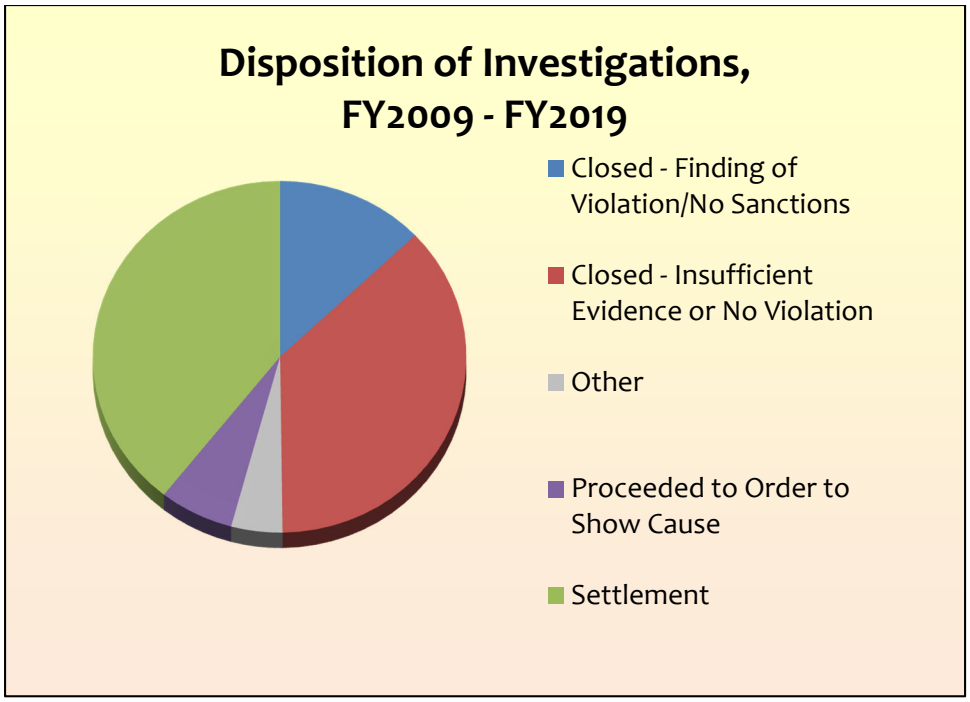



Disposition of Investigations, FY2018
Closed - Finding of Violation/No Sanctions
Closed - Insufficient Evidence or No Violation
Proceeded to Order to Show Cause
Settlement

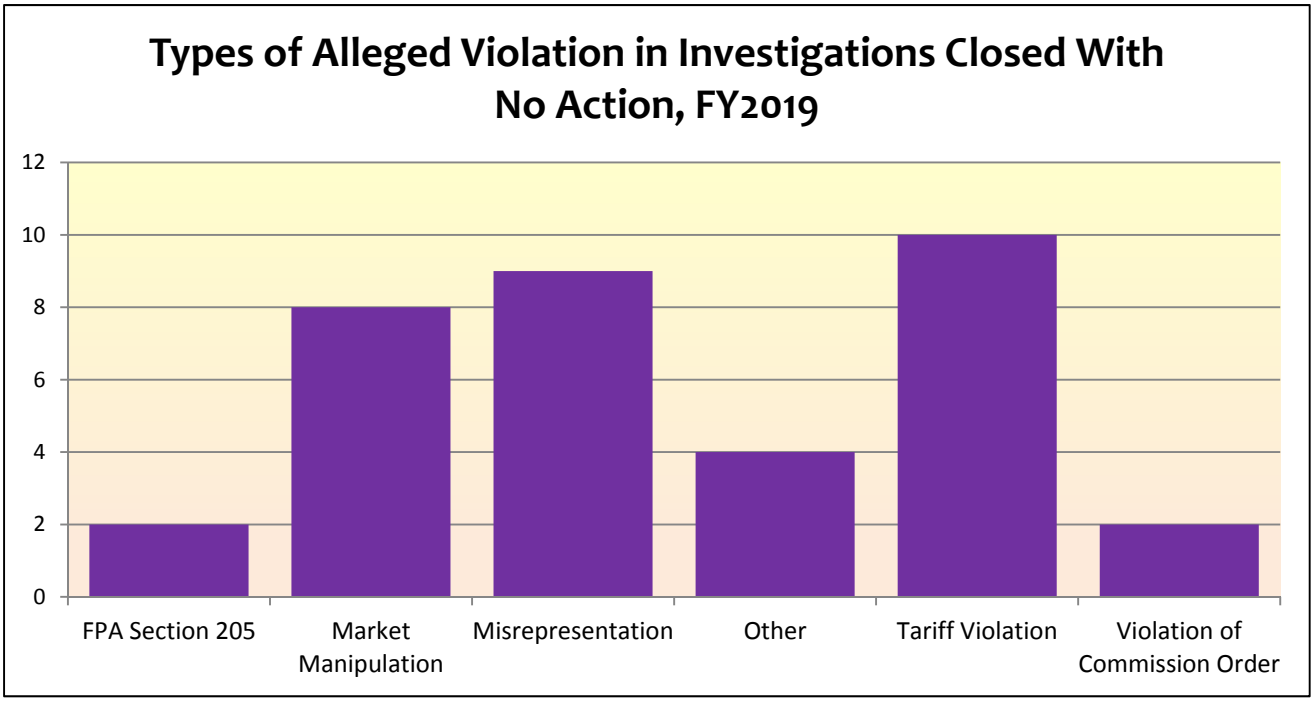

Disposition of Investigations, FY2017
Closed - Insufficient Evidence or No Violation
Settlement

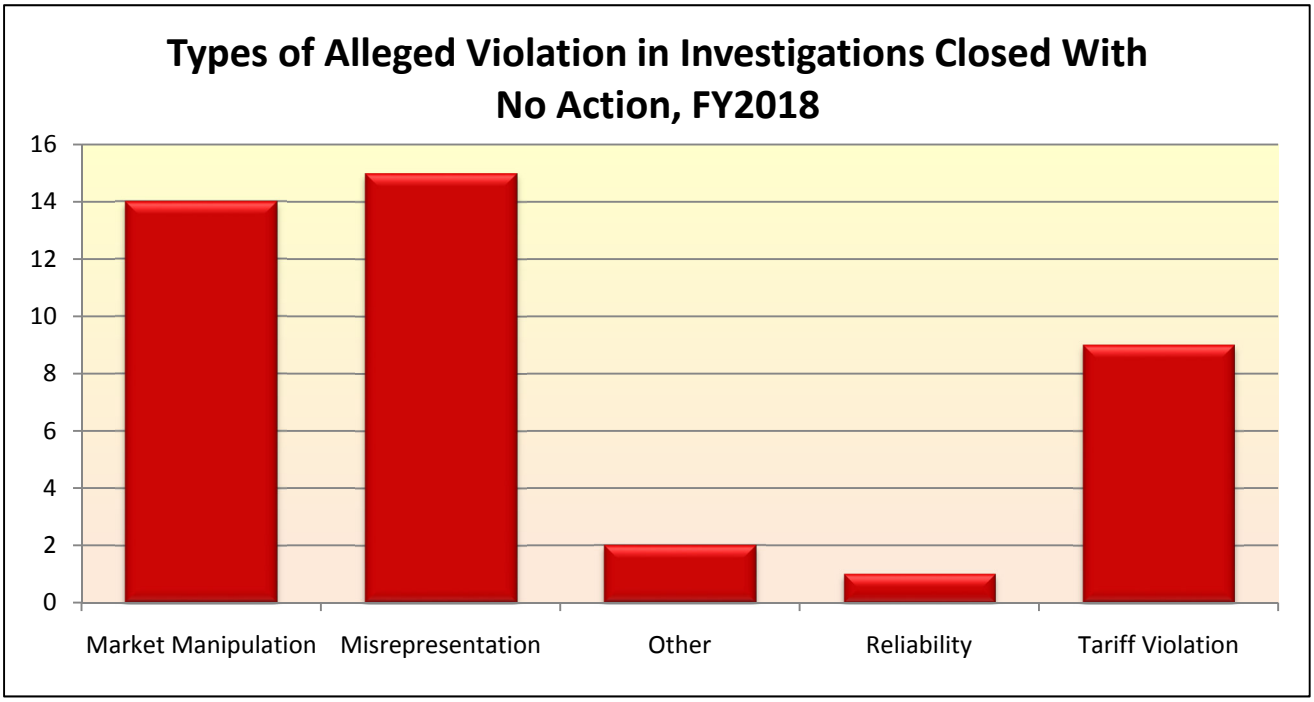

Disposition of Investigations, FY2016
Closed - Insufficient Evidence or No Violation
Proceeded to Order to Show Cause
Settlement

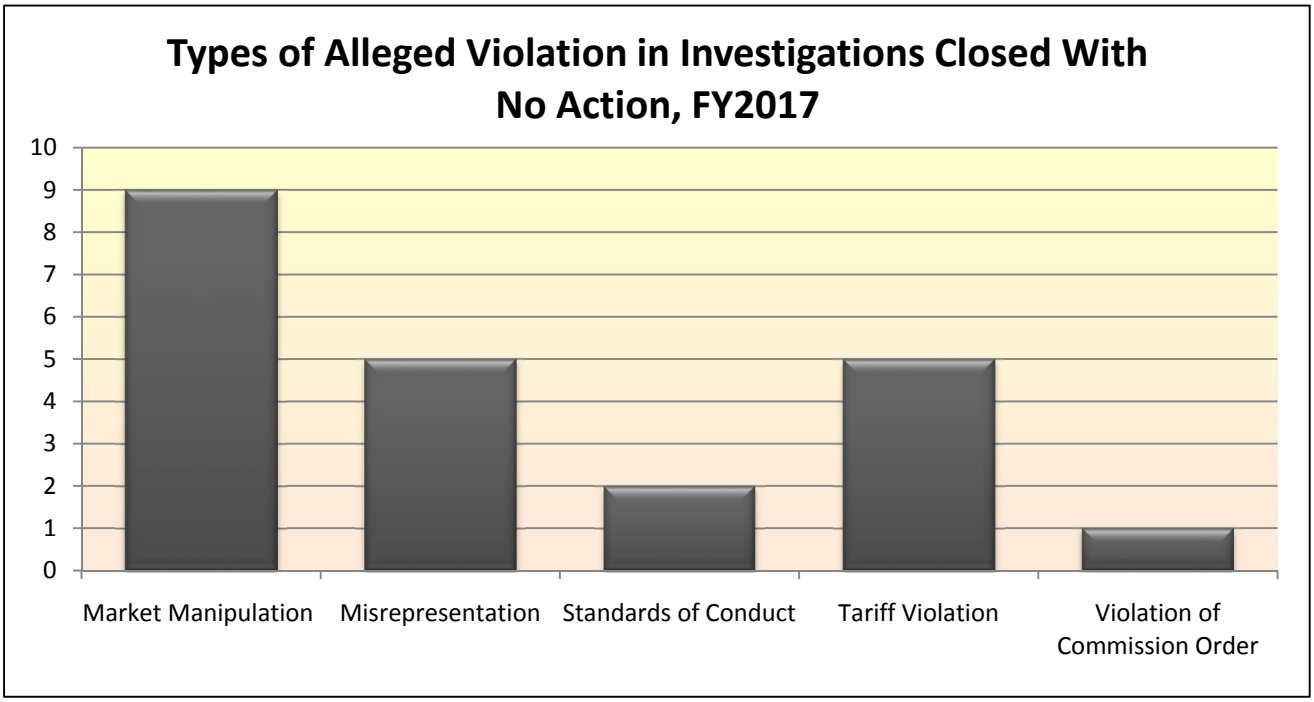

Disposition of Investigations, FY2015
Closed - Finding of Violation/No Sanctions
Closed - Insufficient Evidence or No Violation
Proceeded to Order to Show Cause
Settlement

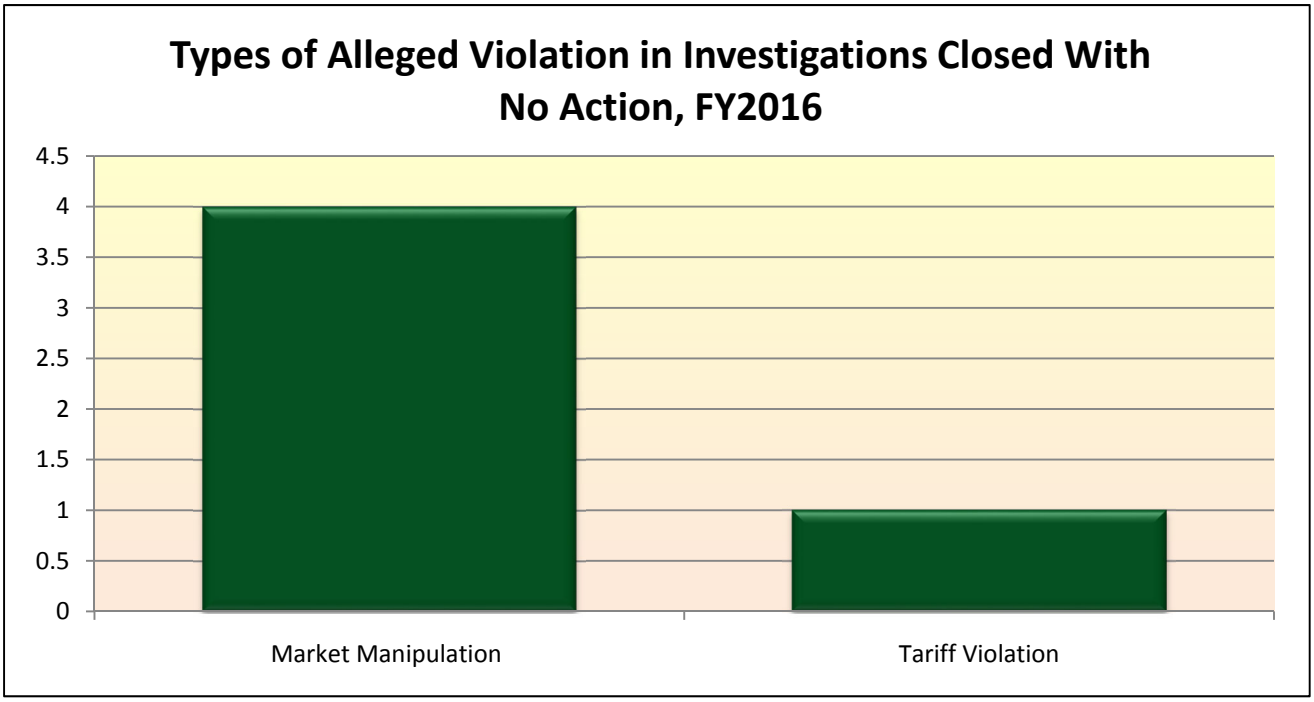


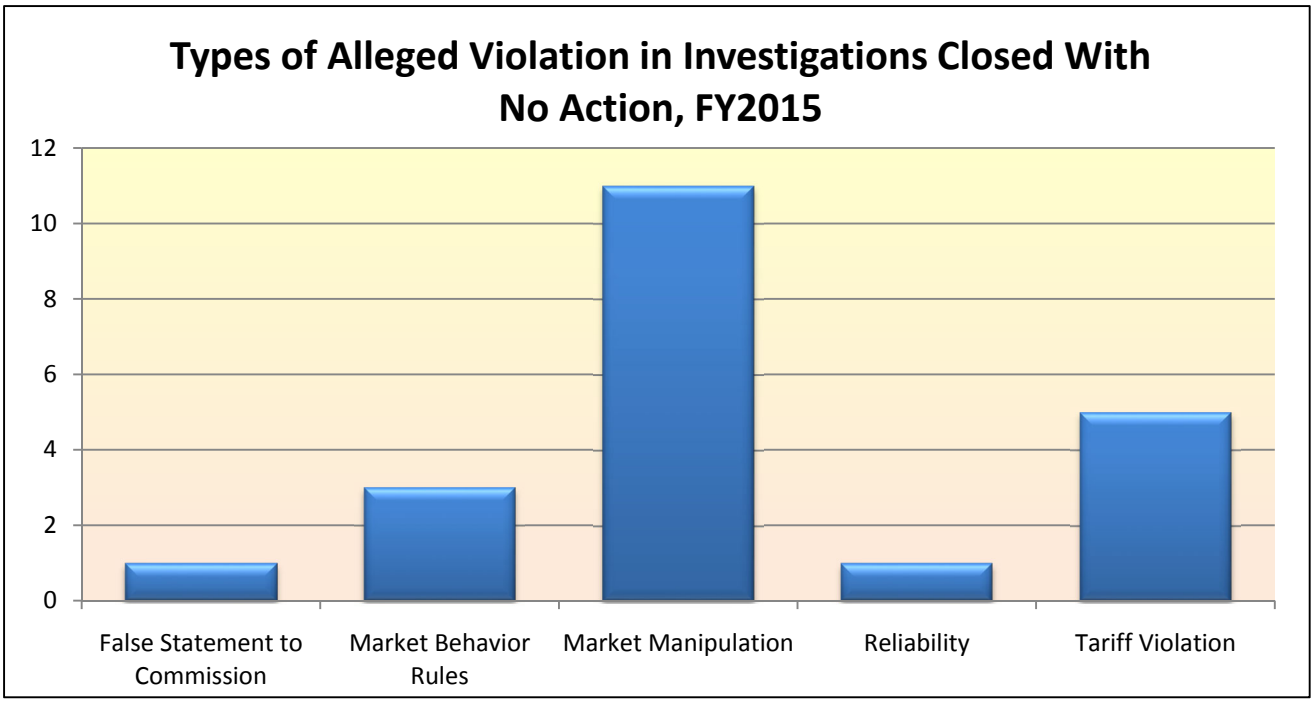

The following charts summarize the nature of the conduct at issue for those investigations that were closed without action in Fiscal Years 2015-2019.




Types of Alleged Violation in Investigations Closed With No Action, FY2018
16
14
12
10
8
6
4
2
0
Market Manipulation
Misrepresentation
Other
Reliability
Tariff Violation


Types of Alleged Violation in Investigations Closed With No Action, FY2017
10
9
8
7
6
5
4
3
2
1
0
Market Manipulation
Misrepresentation
Standards of Conduct
Tariff Violation
Violation of Commission Order




## 2. Illustrative Investigations Closed with No Action

The following summaries of investigations that Enforcement closed without action in FY2019 are intended to provide guidance to the public while preserving the non-public nature of DOI's investigations. In most of the examples, staff provides the relevant market and products involved

in order to provide the maximum level of transparency. However, staff omitted such information in the few examples where such information would risk identifying the investigative subject.

**FPA Section 205 Violation and Tariff Violation (Electric).** Following a referral from the ISO-NE market monitor, staff opened an investigation to determine whether a generator failed to submit accurate energy supply offers related to certain physical parameters in ISO-NE's day-ahead and real-time energy markets, consistent with applicable tariff provisions. During the course of the investigation, staff also learned of a separate potential issue – specifically, that the generator had been making sales for resale without Commission authorization in violation of section 205 of the FPA. Consistent with precedent, the Commission ordered, and the generator made, time-value refunds on the revenues collected on sales made during the period that the generator lacked authorization. On the tariff issue, staff ultimately determined that while certain aspects of the supply offers were inconsistent with the tariff, the generator had made those offers at the direction of ISO-NE employees. In light of this fact, and the generator's payment of time-value refunds on the FPA section 205 issue, staff closed the investigation without further action.

**Hydropower Licensing, Filing Requirements, Misrepresentation, Violation of Commission Order (Hydro).** Following a referral from OEP, staff opened an investigation into a hydropower licensee's failure to comply with the reservoir elevation and water flow requirements in its Commission-issued license and the possible submission of false water flow reports. Staff determined that the licensee is working on a license amendment to resolve the violations regarding the elevation and flow requirements. Staff also determined that the potential false reporting violations ended when the licensee terminated the responsible operator. Finally, staff learned that the licensee is in the process of selling this project (which lessens concerns about future noncompliance by this licensee at this particular project). Accordingly, staff closed the investigation without further action.

**Market Manipulation (Natural Gas).** Following a referral from DAS' Surveillance Group, staff opened an investigation to determine whether two natural gas traders at a commodities trading company violated the Commission's Anti-Manipulation Rule by trading next-day fixed-price natural gas at the Columbia Gulf-Mainline trading hub to benefit index swap positions at that location. Staff's investigation concluded that the traders had not engaged in market manipulation. Staff determined that each trader pursued a separate trading strategy based on market fundamentals and did not find evidence that either trader had made the next-day fixed-price trades to benefit the index swap positions. Staff concluded that one trader's cash trading and index swaps were consistent with a storage arbitrage strategy and that the other trader's cash trading at the hub during the months in question was consistent with his trading behavior at other hubs and in other months, regardless of his financial positions. Accordingly, staff closed the investigation without further action.

**Market Manipulation and Tariff Violation (Electric-Hydro).** Following a market monitor referral, staff opened an investigation to determine whether a power generation and marketing company had violated the Commission's Anti-Manipulation Rule and an ISO's tariff by operating hydroelectric resources in order to obtain unjustified make-whole payments. The market monitor's referral indicated that the company had received in excess of $650,000 in make-whole payments in 2016 by self-scheduling and submitting offers in a way that would make it eligible for the make-whole payments when the hydroelectric resources generated small amounts of energy above their

self-schedules, but within the ISO's threshold for uninstructed deviations (Tolerance Band). Staff's investigation found no evidence that the company had engaged in manipulative conduct. Staff concluded that the deviations in this case (which resulted in the make-whole payments) were inherent in the resource type and not the result of improper activity. Moreover, staff found that the company regularly amended its offers to avoid receiving far greater amounts of make-whole payments. Accordingly, staff closed the investigation without further enforcement action.

**Market Manipulation and Tariff Violation (Electric).** Following a referral from the SPP market monitor, staff opened an investigation to determine whether a commodities trading company had violated the Anti-Manipulation Rule and SPP's Tariff by submitting bids for Transmission Congestion Rights (TCRs) between collocated and "Electrically Equivalent Settlement Locations" (EESLs), even after both the MMU and SPP personnel had advised the company that SPP's Tariff prohibited this practice. Working with the MMU and the investigative subject, staff confirmed that the alleged trades in fact had been submitted. There was no resulting market harm, however, because SPP had identified and removed those trades before the market clearing process took place. Staff also determined that the trader had not deliberately violated the restrictions – a lack of automation in the bidding software allowed for some degree of confusion on the part of the trader. For these reasons, as well as the limited scope of the violations and changes the company made to its trading systems that will ensure no further violations occur, staff closed the investigation without further action.

**Market Manipulation and Tariff Violation (Electric).** Following a referral from the SPP market monitor, staff opened an investigation to determine whether an electric utility: (1) manipulated the physical parameters of its energy offers from a power plant for the purpose of collecting unjustified make-whole payments; or (2) violated SPP's Tariff provisions on offer parameters. The energy offers had unusually high economic minimum limits and were often block-loaded (meaning the economic minimum and economic maximum parameters were set at the same level). The electric utility handled the offers from the plant on behalf of the plant owner, which had obtained qualifying facility (QF) status for the plant under PURPA. Staff found that the utility's offering strategy was not designed to collect make-whole payments and was consistent with the plant's right to sell power as a QF under PURPA. Staff also concluded there was insufficient basis to find a violation of the tariff, which allowed QFs to offer power into the market using a control status that effectively overrode the physical parameters. Accordingly, staff closed the investigation without further action.

**Misrepresentation and Tariff Violation (Electric-Wind).** Following a referral from the MISO market monitor, staff opened an investigation to determine whether certain market participants had violated MISO's Tariff and made misrepresentations to MISO by providing forecasts of output from wind facilities that persistently exceeded actual output. The MMU's referral indicated that the forecasting practices of the referred market participants violated the tariff because they were not unbiased "50/50" forecasts with an equal probability of being high or low. While staff concluded that the market participants were submitting upward biased forecasts, it was not clear whether the specific conduct violated the applicable MISO Tariff language regarding the forecast maximum limit (FML) parameter submitted by market participants to forecast output. Moreover, at the time of the conduct, MISO had yet to specify the requirements for FMLs or how market-participant submitted FMLs would be evaluated by MISO, as directed by a Commission Order on

the relevant tariff provisions. For these reasons, staff determined that the facts did not support pursuit of a violation and staff closed the investigation without further action.

**Misrepresentation and Tariff Violation (Electric-Hydro).** Following a referral from an ISO/RTO's market monitor, staff opened an investigation to determine whether a scheduling coordinator for a hydroelectric resource: (1) violated its duty of candor and accuracy in communications with the ISO/RTO, as required by Commission regulations; and (2) violated the ISO/RTO's Tariff for submitting inaccurate bids for energy and ancillary services and failing to update the resource's availability in the ISO/RTO's outage management system. Staff's investigation found that the scheduling coordinator did not have a repeated pattern of submitting inaccurate, or infeasible, bids. Moreover, the outage coordinator largely complied with the ISO/RTO's Tariff's requirement to submit outage cards when water levels rendered the resource's day-ahead bids infeasible in real-time and its limited failures to submit outage cards were inadvertent. The limited violations which occurred resulted in only minimal market harm. Also, during staff's investigation, the subject stopped serving as the scheduling coordinator for the hydroelectric resource in question. Accordingly, staff closed the investigation without further action.

**Tariff Violation (Electric).** Following a referral from the NYISO market monitor, staff opened an investigation into an entity's failure to submit energy offers into NYISO's Day-Ahead Market (DAM) on three days in 2017 for two generation facilities it operated. At the time of these incidents, both generators were capacity resources for which the entity was receiving installed capacity payments. Pursuant to its tariff, NYISO assessed penalties for the violations. For one of the generators, staff determined that the entity's failure to bid into the DAM was due to human error. The employee tasked with making the bid accidentally inserted the wrong date into the system. In the case of the other generator, a large hole was discovered in the duct work at the generation facility, leading to a forced outage. The generator notified its transmission operator of the outage but failed to similarly notify NYISO. Staff's investigation found no deliberate misconduct and no market price impact. For these reasons, and because significant actions were taken to prevent re-occurrence, staff closed the investigation without further action.

## F. MMU Referrals

ISO and RTO Market Monitoring Units (MMUs) perform a critical function surveilling organized electric markets to detect potential violations, including market manipulation, anticompetitive behavior, and tariff noncompliance. As the Commission has recognized, "effective market monitoring requires close collaboration between the [MMUs], RTOs, ISOs, and [Enforcement]."[20] This collaboration occurs formally, through certain reporting requirements in Commission regulations, as well as informally, through regular dialogue with Enforcement. Both types of collaboration facilitate a high level of situational awareness among Enforcement staff and ensures a robust knowledge base for investigations. In an effort to promote transparency and provide guidance to regulated entities and MMUs, this section highlights the MMUs' functions, describes the types of conduct MMUs monitor and refer to Enforcement, and provides illustrative

[20] *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,046, at P 20 (2011).

examples of MMU referrals that Enforcement closed in FY2019 as initial inquires without conversion to an investigation.

By regulation, MMUs are required "to make a non-public referral to the Commission in all instances where the [MMU] has reason to believe that a Market Violation has occurred."[21] This referral requirement applies to potential "misconduct by the RTO or ISO, as well as by a market participant."[22] The Commission has not prescribed a specific level of detail or length for referrals. However, they must be (1) non-public, (2) in writing, and (3) addressed to the head of Enforcement with copies to the heads of OEMR and OGC.[23] In addition, they must include: (1) "sufficient credible information to warrant further investigation by the Commission;" (2) the names and contact information for suspected violators; (3) the dates of the violations and whether the behavior is ongoing; (4) the rule, regulation, or tariff provisions violated; (5) the specific conduct; (6) the consequences to the market; (7) if the referral includes manipulation, a description of the manipulative effect; and (8) any other information the MMU wishes to include.[24] There is also a continuing obligation to update referrals with any information the MMU learns that is "related to the referral."[25] After receiving a referral, Enforcement conducts an inquiry into the alleged conduct and determines whether to open a full investigation.

To help facilitate these regulatory requirements, Enforcement assigns staff to serve as liaisons with the MMUs for each RTO or ISO as well as with the RTO and ISO itself. MMUs refer a wide range of potential violations – both in terms of type and seriousness. Examples of referrals illustrating this broad range include: (1) referral of JP Morgan Ventures Energy Corporation for manipulation and tariff violations related to allegedly abusive bidding practices in CAISO and MISO;[26] (2) referral of Westar Energy for potential violations of the SPP Tariff and Commission

[21] 18 C.F.R. § 35.28(g)(3)(iv)(A) (2019). A Market Violation is a violation of a tariff, Commission order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies. *Id.* § 35.28(b)(8).

[22] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071, at P 311 (2008).

[23] 18 C.F.R. § 35.28(g)(3)(iv)(B)-(C) (2019).

[24] *Id.* § 35.28(g)(3)(iv)(D).

[25] *Id.* § 35.28(g)(3)(iv)(E). Separate and apart from this referral requirement, MMUs also must "[i]dentify and notify [Enforcement] of instances in which a market participant's or [ISO's/RTO's] behavior may require investigation, including, but not limited to, suspected Market Violations." 18 C.F.R. § 35.28(g)(3)(ii)(C) (2019). These notifications are more informal, can be made orally or in writing, and do not require the documentation involved in a referral.

[26] *In Re Make-Whole Payments and Related Bidding Strategies*, 144 FERC ¶ 61,068 (2013) (approving settlement agreement that included a $285 million civil penalty and $125 million in disgorgement).

regulations for allegedly submitting inaccurate cost inputs in its mitigated energy offers;[27] and (3) referral of Etracom LLC for an alleged cross-market manipulation scheme in CAISO.[28]

## 1. Statistics on MMU Referrals

In FY2019, staff received 16 new MMU referrals. Of these referrals (some of which involved more than one type of violation or multiple subjects), 11 involved potential market manipulation, seven involved potential tariff violations, and four involved misrepresentations prohibited by the Commission's market behavior rules. Three of these MMU referrals were the source for three investigations opened this fiscal year. Enforcement also received two supplemental referrals of two entities that were already being investigated for the conduct described in the referrals. As such, these supplemental referrals were rolled into those existing investigations. Of the MMU referrals received in FY2019, seven remained pending at the end of the fiscal year.

DOI staff elected not to open full investigations of 10 MMU referrals in FY2019, four of which were carried over from the previous fiscal year. These were analyzed and closed as inquiries. Of these referrals (some of which involved more than one type of violation or multiple subjects), seven involved potential market manipulation, eight involved potential tariff violations, and five involved misrepresentations prohibited by the Commission's market behavior rules.

Of the 10 MMU referrals that staff did not convert to full investigations, six were closed without further action because staff concluded that the evidence did not support finding a violation. In four other MMU referrals, a violation was found but staff did not pursue a sanction.

## 2. Illustrative MMU Referrals Closed with No Action

Enforcement presents the following illustrative examples of MMU referral inquiries that DOI staff closed in FY2019 without conversion to an investigation. In determining whether to open an investigation based on an MMU referral, staff considers the factors set forth in the Commission's Revised Policy Statement on Enforcement.[29] The illustrative summaries below are intended to provide guidance to the public and to regulated entities as to why staff chose not to pursue an investigation or enforcement action, while preserving the non-public nature of the MMU referral.

**Market Manipulation.** Following a referral from the SPP MMU, staff analyzed but did not open an investigation into whether the two separate ownership groups of a jointly-owned unit (JOU) violated the Commission's Anti-Manipulation Rule when they submitted similar cost-based and competitive offer curves. The MMU questioned whether the similar curves resulted from collusion between the two groups. The referral noted that each ownership group had received one unjustified

[27] *Westar Energy, Inc.*, 160 FERC ¶ 61,025 (2017) (approving settlement agreement that included a civil penalty of $180,000 and an admission to the violations).

[28] *Etracom LLC*, 155 FERC ¶ 61,284 (2016) (Order Assessing Penalties) (Etracom). Etracom ultimately settled with Enforcement. *See Etracom LLC*, 163 FERC ¶ 61,022 (2018) (approving settlement agreement that included a civil penalty of $1.9 million).

[29] Revised Policy Statement, 123 FERC ¶ 61,156 at P 25.

make-whole payment during this period. Staff determined that although SPP's Tariff permitted each unit share of the JOU to be modeled and committed independently, the owners' inability to actually operate the shares independently required that the resource be registered under a provision in which commitment decisions were based on aggregated data from each ownership share (Combined Resource Option). Staff concluded that it was reasonable that unit-wide costs would lead to similar cost-based offers for each ownership group. As for the similarity of the competitive offer curves, staff concluded that this was largely explained by tariff specifications that eliminated variation with respect to certain offer parameters and the central role of the owner-operator in supplying parameters for each of the two ownership shares. Subsequent to the MMU's referral, the Commission accepted SPP's elimination of the Combined Resource Option because of difficulties in administering this registration option. Finally, staff concluded that there was insufficient evidence to demonstrate that the single unjustified make-whole payment to each ownership group was necessarily the result of collusion. For these reasons, staff closed this MMU Referral without further action.

**Market Manipulation.** Following a referral from the CAISO MMU, staff analyzed but did not open an investigation into whether six market participants violated the Commission's Anti-Manipulation Rule by cutting scheduled exports from CAISO to the Centro Nacional de Control de Energia (CENACE) Baja Norte system. CENACE operates Mexico's wholesale electricity markets, including the Baja California region of Mexico. The MMU questioned whether the market participants were engaged in an arbitrage scheme whereby they sold in CENACE's day-ahead market at a high price, then cut the schedule, did not deliver power in real time, and then bought back the power at lower real-time prices. Staff determined that there were a variety of acceptable reasons for the observed cuts, which occurred primarily for reasons out of the market participants' control. Given the relative deadlines for submission of offers in the CENACE and CAISO day-ahead markets, inter-market coordination on bidding was extremely difficult. The CAISO day-ahead market offers had to be submitted before the market participant could know the exact amount of power that its counterparty cleared in the CENACE day-ahead market. Staff also confirmed with the CENACE market monitor that, except when CENACE or CAISO orders a cut, an entity cannot profit by buying back its day-ahead schedule. For these reasons, staff closed this MMU referral without further action.

**Market Manipulation and Misrepresentation.** Following a referral from the SPP MMU, staff analyzed but did not open an investigation into whether a large owner-operator of renewable generation projects had: (1) violated the Commission's Anti-Manipulation Rule by trading virtual products to benefit certain of its Transmission Congestion Revenue (TCR) positions; and (2) violated section 35.41(b) of the Commission's regulations by making certain misrepresentations to the MMU as part of its explanation that these trades were part of a hedging strategy. Staff reviewed the company's trades over a five-month period in 2018 and determined that the company had not placed virtual trades in large enough quantities or at the right times to have a deliberate impact on its associated TCR positions. As such, no harm resulted from the company's virtual trading nor did the company benefit from it. Staff also spoke with relevant personnel at the company, who explained that its virtual trading aimed to hedge the real-time congestion exposure of three of its wind resources by using virtual transactions, and it, therefore, based its virtual volume on the wind forecast. Staff confirmed that the company's minimum and maximum virtual supply offers matched SPP's wind forecast, on average, 86.6 percent of the time. The company also credibly explained the mismatch between its virtual and TCR volumes which had been

observed and questioned by the MMU. Staff also confirmed that the company did not engage in any speculative virtual trading at the locations of interest – every virtual supply offer/demand bid at a node was connected to an asset. Finally, since the MMU's referral, the company took steps to eliminate the need for these virtual transactions by implementing dynamic scheduling at two of the three wind resources. For these reasons, staff closed this MMU referral without further action.

**Misrepresentation and Tariff Violation.** Following a referral from MISO's MMU, staff analyzed but did not open an investigation into whether a combined cycle unit violated MISO's Tariff and section 35.41(b) of the Commission's regulations by failing to update real-time offers to reflect a reduction in the unit's production capability. The unit did not follow MISO dispatch instructions to ramp up output for several hours due to an emission issue causing insufficient steam production. The unit's operator informed its real-time desk of the need to reduce the unit's economic maximum, but the real-time dispatcher failed to do so. Staff determined that, although the failure to update real-time offers to reflect the unit's reduced capability was likely a tariff violation, the conduct was inadvertent, and staff was unaware of any similar past incidents involving the unit. In addition, staff determined that the resulting uplift payments were minimal and that the market participant had taken corrective measures to ensure offers are properly updated in the future. For these reasons, staff closed this MMU referral without further action.

**Misrepresentation and Tariff Violation.** Following a referral from MISO's MMU, staff analyzed but did not open an investigation into whether a unit of a coal-fired generation plant violated MISO's Tariff and section 35.41(b) of the Commission's regulations by failing to update its real-time offers to reflect a reduction in the unit's output caused by a mechanical problem. The unit's dispatcher immediately entered an off-control designation when the equipment problem occurred, but did not revise the unit's real-time offer to reduce its economic maximum. As a result, when the off-control designation lapsed, the unit failed to follow MISO dispatch instructions to ramp up based on its offered capability. Staff determined that, although the failure to update real-time offers to reflect the unit's reduced capability was likely a tariff violation, the conduct was inadvertent and the market participant refunded to MISO the uplift payments it had received for the period when the unit failed to ramp up. The market participant also implemented remedial measures to prevent such incidents in the future and cooperated with staff in providing information about the incident. For these reasons, staff closed this MMU referral without further action.

**Tariff Violation**. Following a referral from PJM's MMU, staff analyzed but did not open an investigation into whether two market participants had violated the PJM Tariff by improperly including certain variable operating expenses in their cost-based offers. The MMU alleged that not only had these costs been included in violation of the PJM Tariff, but also that some of the costs had been double counted. The MMU raised these concerns to staff following PJM's approval of the costs at issue. Following the referral, staff discussed the matter with the companies, PJM, and the MMU. Additionally, staff analyzed data related to the claimed costs and conducted extensive research into the relevant portions of the PJM Tariff. Staff determined that it was not clear whether the tariff prohibited the types of costs at issue. For this reason, and because PJM had approved the costs, staff closed this MMU referral without further action.

**Tariff Violation.** Following a referral from MISO's MMU, staff analyzed but did not open an investigation into whether a generation unit violated MISO's Tariff by failing to follow MISO's dispatch instructions. The dispatch deviations occurred when the unit, which is pseudo-tied to

PJM, received instructions from both MISO and PJM to ramp up. In response, the unit's overall output and its PJM share of output increased, but its MISO output remained flat or decreased. The market participant determined that the cause of the MISO dispatch deviations was an error in the unit's generation control system's allocation of ramp and output between PJM and MISO. Staff determined that, although the dispatch deviations possibly violated the applicable business practice manual and the tariff, they were not intentional. In addition, the market participant acknowledged the deviations, promptly investigated their cause and instituted corrective measures, cooperated with staff in providing information about the deviations, and did not receive uplift payments for the unit on the days when the deviations occurred. For these reasons, staff closed this referral without further action.

## G. Enforcement Hotline

DOI staff fields calls and other inquiries made to the Enforcement Hotline (Hotline).[30] The Hotline is a means for people, anonymously if preferred, to inform Enforcement staff of potential violations of statutes, Commission rules, orders, regulations, and tariff provisions. When staff receives information concerning possible violations, such as allegations of market manipulation, abuse of an affiliate relationship, or violation of a tariff or order, staff researches the issue presented and often consults other members of the Commission's staff with expertise in the subject matter of the inquiry. In some cases, Hotline calls lead to investigations by DOI.

In FY2019, Enforcement received 153 Hotline calls and inquiries, 148 of which were promptly resolved within the fiscal year through advice provided by staff, because the caller stopped responding to staff's communications, or because the matter was already before the Commission and so staff could not discuss it with the caller. Staff also closed two Hotline matters that had been pending from the previous year. One Hotline call was the source of an investigation opened this fiscal year. Of the Hotline calls received in FY2019, five remained pending at the end of the fiscal year.

Every year, a significant percentage of the Hotline calls and inquiries relate to subjects outside of the Commission's jurisdiction or contested matters pending before the Commission. DOI staff resolves these matters by advising the callers where they may find the information they need, or directing them to the appropriate Commission office or docketed proceeding.

## H. Other Matters

In addition to its investigative work, DOI staff worked on other important matters in FY2019, including:

**Collaboration with Other Commission Offices.** DOI staff regularly coordinates with other Commission program offices regarding potential enforcement matters. This includes working closely with OEP and OGC on pipeline certificate and hydroelectric licensing matters to ensure compliance with statutory and regulatory obligations, as well as the terms and conditions of pipeline certificates and hydroelectric licenses and exemptions. In addition, DOI staff works

[30] *See* 18 C.F.R. § 1b.21 (2019).

closely with OGC, OEMR, and OEPI regarding late filings submitted under sections 203 or 205 of the FPA. There were more than 170 such late filings during FY2019 that DOI staff reviewed. Staff also worked closely with OGC and OEMR on evaluating refund reports related to the late filings. OGC and OEMR regularly consult with DOI staff when a qualifying facility submits a request for a declaratory order and/or a request for waivers of various provisions of Part 292 of the Commission's regulations related to small power production and cogeneration under PURPA. Regulated entities can submit questions to the Compliance Help Desk to reduce their risk of subsequent findings of noncompliance and potential enforcement actions. DOI staff assisted in four Compliance Help Desk inquiries in FY2019. Finally, OGC and OEMR confer with DOI staff for prefiling meetings and/or regarding requests involving the Standards of Conduct under Order No. 717 or Affiliate Restrictions under Order No. 697. During FY2019, DOI staff was involved in ten such matters.

**Hydropower Compliance.** OEP's Division of Hydropower Administration and Compliance (DHAC) has authority over hydropower compliance matters until such matters are referred to Enforcement. DOI staff provided significant input and advice to DHAC regarding three projects involving dam safety and other violations within DHAC's authority during FY2019.

**No-Action Letters.** Enforcement is one of several offices within the Commission that is jointly responsible for processing requests seeking a determination whether staff would recommend enforcement action against the requestor if it pursued particular transactions or practices. The "No-Action Letter" can be a useful tool for entities subject to the Commission's authority to reduce the risk of failing to comply with the statutes the Commission administers, the orders, rules or regulations thereunder, or Commission-approved tariffs.[31] FERC staff is generally available to confer on a pre-filing basis for possible "No-Action Letter" requests. During FY2019, Enforcement assisted with processing one such request.

**Reliability Coordinator.** As part of its cooperation with other program offices, Enforcement has a designated Reliability Coordinator who is a member of DOI staff. In addition to serving a leadership role in inquiries or investigations involving reliability of the Bulk-Power System, the Reliability Coordinator serves as a team member on reliability-related matters including NERC and Regional Reliability Entity filings (e.g., Notices of Penalty, changes to NERC Rules, amending or retiring Reliability Standards, NERC Five-Year Assessments, and similar periodic filings). Enforcement's Reliability Coordinator also makes presentations to NERC and at Regional Entity meetings, such as those of the Member Representative, Operating, and Planning Committees.

**Revision of Maximum Civil Penalties.** The Federal Civil Penalties Inflation Adjustment Act Improvements Act of 2015 requires all Federal agencies to make annual inflation adjustments to the maximum civil penalties that may be assessed under the laws administered by those agencies.[32] Pursuant to that statutory obligation, DOI proposed for Commission approval an

[31] *See Interpretive Order Modifying No-Action Letter Process and Reviewing Other Mechanisms for Obtaining Guidance,* 123 FERC ¶ 61,157 (2008).

[32] *See* Federal Civil Penalties Inflation Adjustment Act Improvements Act of 2015, Pub. L. 114-74, § 701, 129 Stat. 584, 599 (2015).

instant final rule increasing the civil penalties that the Commission may assess under the FPA, the NGA, the Natural Gas Policy Act of 1978, and/or the Interstate Commerce Act.[33] The Commission adopted that rule on January 8, 2019, and the revised maximum penalties took effect on February 1, 2019.

[33] *See* Civil Monetary Penalty Inflation Adjustments, Order No. 853, Docket No. RM19-9-000, 166 FERC ¶ 61,014 (2019), 84 Fed. Reg. 966 (Feb. 1, 2019).

# DIVISION OF AUDITS AND ACCOUNTING

## A. Overview

The Division of Audits and Accounting (DAA) administers Enforcement's audit and accounting programs to support the Commission's mission to assist consumers in obtaining reliable and efficient energy service, at a reasonable cost, through appropriate regulatory and market means. DAA's primary goal in conducting its audit and accounting activities is to enable the Commission to achieve its strategic objectives by assisting in the development of just and reasonable rates and increasing compliance with Commission regulations and policies.

DAA's audit program supports the Commission's strategic objectives through public risk-based audits. DAA performs various types of audits that respond to the needs of the Commission, public, and industry, and advises the Commission on compliance and other matters. The audit program serves as a resource for the Commission to examine risk areas within the regulated industries and inform the Commission's actions regarding rates, tariffs, financial and operational transparency, policy initiatives, law, reliability, and other areas in the electric, natural gas, and oil industries. DAA audits also provide jurisdictional entities an opportunity to work with audit staff to evaluate and improve their overall compliance, and to identify potential areas of noncompliance before they escalate. For the Commission's regulated industries, DAA's publicly issued audit commencement letters and audit reports provide insight into and valuable guidance on areas of emphasis and concern.

DAA's accounting program is a vital component of the Commission's strategic goal of establishing just and reasonable cost of service rates, terms, and conditions by: (1) overseeing the accounting and reporting of financial information affecting cost of service rates; (2) acting as the focal point for interpretive guidance concerning the Commission's financial accounting and reporting rules, orders, regulations, and statutes; and (3) advising the Commission and industry on accounting and other financial issues. The accounting program facilitates the consistent reporting of financial information and ensures that an entity's operations are reported in a manner that most appropriately supports ratemaking analysis. DAA's accounting program also provides accounting expertise to the Commission's other program offices and assists in the development of Commission policies and proposed rulemakings to ensure these initiatives properly consider and evaluate the related accounting and financial issues.

## B. Outreach and Guidance

DAA's programs, through their outreach and guidance, inform the industry, the public, and others about what constitutes effective compliance, accountability, and transparency. The goal of DAA's outreach is to provide jurisdictional entities with ample opportunity to achieve compliance and avoid noncompliance that may result in harm to jurisdictional customers and energy markets. DAA actively engages in regular industry outreach with trade associations, such as the Interstate Natural Gas Association of America, Edison Electric Institute, Association of Oil Pipe Lines, and Natural Gas Supply Association, and encourages interested parties to contact DAA with any inquiries or concerns. As a result of such interactions, DAA considers opportunities to enhance the efficiency, transparency, and effectiveness of its audit and accounting programs. For example,

in response to industry comments, DAA adopted a process of formally notifying a company by email from the Director of DAA of the close of an audit proceeding when the compliance implementation stage has been completed. DAA also engages with state regulators and the public accounting firms that audit and certify jurisdictional entities' financial reports. Such industry outreach contributes to DAA's analysis of accounting trends affecting jurisdictional entities and issuances of accounting guidance by the Chief Accountant. For example, in FY2019, guidance was issued for lease accounting in Docket No. AI19-1-000. DAA continues to provide formal accounting guidance in response to accounting requests filed with the Commission. Informal accounting guidance may be requested and obtained from DAA via email (accountinginquiries@ferc.gov) and phone ((202) 502-8877). Informal guidance on all other compliance matters may be obtained through the Compliance Help Desk.[34]

## C. Compliance

### 1. Compliance Programs

It is imperative that companies establish and maintain effective compliance programs. Such programs should foster a culture of compliance that begins at the executive level and permeates throughout the organization. Effective compliance programs increase the likelihood that jurisdictional companies will understand and follow the Commission's rules, regulations, and orders, as well as their own tariff provisions, both in letter and spirit. However, since each company is unique in terms of size, region, organizational structure, and other relevant characteristics, no two compliance programs are alike. Each company must tailor its program to the specific challenges it faces. Notwithstanding these differences, DAA has found that the strongest compliance programs include:

- A proactive program that:
  - Equips staff and management with sufficient training, education, tools, and other resources to detect issues in a timely manner to correct or prevent noncompliance;
  - Provides effective lines of communication and notifies staff of standards through well-publicized policies and procedures;
  - Stays abreast of compliance trends by reviewing Commission orders and audit reports, and evolves based on these trends and other developments in the industry.
- The active involvement of senior management to provide a tangible demonstration of "tone-from-the-top" as well as the allocation of funds necessary for such programs.
- A designated compliance officer and compliance committee, charged with development and oversight of compliance activities and metrics that assess program effectiveness.

[34] Information about the Commission's Compliance Help Desk is available at www.ferc.gov/contact-us/compliance-help-desk.asp.

- The active involvement of internal audit and monitoring functions to routinely assess compliance with tariff provisions and Commission rules, orders, and regulations, to foster a strong and sustainable culture of commitment to compliance on an enterprise-wide basis.
- A policy and culture of seeking guidance from the Commission as necessary to ensure compliance, including an effective process to self-report noncompliance identified through internal oversight activities.

DAA appreciates the time, effort, and cooperation that each company puts forth during the course of an audit. A company's willingness to proactively assist DAA not only demonstrates its commitment to compliance, but also can have a positive impact on the timeliness of the audit itself.

## 2. Timely Remedy of Noncompliance

Equally important to a robust compliance program is the timely remedy of noncompliance. Although an effective compliance program will often prevent noncompliance with Commission rules, regulations, and orders, any instances of noncompliance should be addressed immediately. Timely implementation of audit recommendations helps maximize their impact, demonstrates commitment to compliance, and supports fair, competitive markets. DAA tracks every audit recommendation it makes, and works with each company until all recommendations have been fully implemented. Further, the Commission's FY2018-2022 Strategic Plan encourages strong compliance programs and places emphasis on timely implementation of corrective actions within six months of audit completion.[35] In FY2019, 97 percent of DAA's audit recommendations were implemented within six months.

## 3. Compliance Alerts

DAA continues to observe certain areas in which compliance has been problematic for some entities. DAA believes that highlighting these areas for jurisdictional entities and their corporate officials will increase awareness of these concerns and facilitate compliance efforts. The topics presented below represent areas where DAA has found recurring compliance concerns or noncompliance of significant impact. DAA believes that greater attention in these areas will enable jurisdictional entities to prevent noncompliance, thereby avoiding enforcement actions. To assist in gaining a better understanding of a particular topic, the docket number(s) of one or more recent audit reports or Commission orders dealing with that topic are provided in the discussions below.

**Allocated Labor.** Companies have charged labor and labor-related costs to construction projects without using an appropriate cost allocation method or time tracking process to ensure capitalized labor costs have a definite relation to construction. Specifically, DAA has observed that allocation methods were not properly designed, nor were the allocation results sufficiently monitored to ensure that costs charged were appropriately allocated to capital projects when employees: (1) performed activities that only supported the operations of the existing infrastructure; (2) spent a portion of their time performing construction-related activities and a portion on other jurisdictional

[35] *See* Strategic Plan, *supra* note 4, at 7 (Objective 1.2: Performance Measure).

activities; or (3) performed activities supporting both jurisdictional and nonjurisdictional activities. (PA16-2-000, PA16-4-000).

**Allowance for Funds Used During Construction (AFUDC).** Recent audit activity has shown deficiencies in how jurisdictional entities have calculated AFUDC, resulting in excessive accruals. Short-term debt is regarded as the first source of funding construction activities in the AFUDC calculation, and the short-term debt rate is derived using an estimate of the cost of short-term debt for the current year. DAA has found instances where a company used commitment fees associated with lines of credit in the calculation of the short-term debt rate. Under Order No. 561, Commission approval is required to include such fees as part of the AFUDC short-term rate derivation (PA18-2-000).

Other common findings related to AFUDC during audits include:

- Failure to exclude goodwill-related equity from the equity component of the AFUDC rate (PA10-13-000);
- Computing AFUDC on contract retention and other noncash accruals (FA17-6-000);
- Compounding AFUDC more frequently than semi-annually (AC12-53-000);
- Improperly using monthly equity and long-term debt balances instead of prior-year-end balances in computing the AFUDC rate (FA17-1-000, PA18-2-000);
- Improperly including Account 216.1, Unappropriated Undistributed Subsidiary Earnings, and Account 219, Accumulated Other Comprehensive Income, balances as part of the equity component of the AFUDC formula (FA18-2-000, FA18-3-000, PA18-2-000);
- Employing the net-of-tax approach when performing AFUDC calculations (AC18-63-000); and
- Improperly using an AFUDC methodology not prescribed by the Commission that results in capitalized AFUDC above the maximum permitted by the Commission's regulations (PA16-4-000).

**Formula Rate Matters.** A focal point of DAA's formula rate audits continues to be compliance with the Commission's accounting and FERC Form No. 1, Annual Report of Major Electric Utilities, Licensees and Others (FERC Form No. 1), requirements for costs that are included in formula rate recovery mechanisms used to determine billings to wholesale customers. DAA notes that certain areas of noncompliance could have been prevented with more effective coordination between jurisdictional entities' accounting and rate staffs to prevent the recovery of costs that should have been excluded from the formula rate. Additionally, formula rate audits in recent years have identified patterns of noncompliance in the following areas:

- Revenue Credits – Public utilities understated the revenue credits that were used to reduce the revenue requirements of their transmission formula rates by improperly excluding certain transmission-related revenues. (FA17-2-000 (pole attachment revenue), FA18-3-000 (rent from affiliate)).

- Income Tax Overpayments – Public utilities have incorrectly recorded in Account 165, Prepayments, income tax overpayments for which they elected to receive a refund and not have such overpayments applied to a future tax year's obligation. This has led to excess recoveries through formula rate billings. These costs are properly recorded in Account 146, Accounts Receivable from Associated Companies, or Account 143, Other Accounts Receivable, as appropriate. (FA17-4-000, FA13-1-000).
- Excess Accumulated Deferred Income Taxes (ADIT) – To address the tax effects of the Tax Cuts and Jobs Act of 2017 (TCJA), public utilities adjusted ADIT balances to reflect the change in the effective corporate tax rate from 35 percent to 21 percent. Under certain formula rate tariffs, public utilities were required to make adjustments to neutralize the rate base impacts of these TCJA adjustments to ADIT balances. Audit staff found instances where utilities removed balances from the ADIT accounts but did not make the necessary adjustments to keep rate base neutral. This led to rate base being overstated and wholesale transmission customers being overbilled. (FA18-3-000).
- Storm Damage – Public utilities have collected excess storm damage amounts from wholesale customers by either recovering estimates that did not reflect actual experience or recovering both estimated and actual storm damage expenses. (FA15-5-000, FA15-6-000, FA16-4-000).
- Investment Tax Credits (ITCs) – Public utilities have improperly accounted for ITCs associated with utility plant as income tax prepayments in Account 165. ITCs are generated as a result of investments made in utility plant. DAA found instances in which tax credits were used to reduce taxable income, but not all of the ITCs were used at once and resulted in an ITC carry-forward. DAA found that ITC carry-forwards were recorded in an incorrect account and factored into formula rate billings, leading to customer overbillings. (FA15-8-000).
- Internal Merger Costs – Public utilities have included merger-related transaction costs in operating expense accounts, contrary to the long-standing Commission policy that such costs be recorded in non-operating expense accounts. This accounting resulted in companies misrepresenting utility operating income and expenses reported in their FERC Form No. 1. In addition, public utilities subject to hold-harmless commitments have incorrectly recovered merger-related transaction and transition costs, including internal labor costs, in rates. Public utilities should obtain Commission approval to recover such costs and otherwise should have appropriate controls and procedures to ensure that the costs are tracked and excluded from formula rates. (FA16-3-000, FA17-1-000, FA18-3-000, FA14-10-000, PL15-3-000).
- Asset Retirement Obligations (ARO) – Public utilities included ARO amounts in formula rates without explicit Commission approval, including the asset component that increases rate base, the depreciation expense related to the asset, and the accretion expense related to the liability. (PA18-2-000, FA13-1-000).
- Commitment Fees – Public utilities improperly recorded commitment fees associated with lines of credit in Account 165, Prepayments, which led to excess recoveries through formula rate billings. (FA15-5-000, FA15-6-000, FA15-7-000).

- Formula Rate Errors – Public utilities' transmission formula rates contained errors, omissions, and miscalculations related to various accounts. Some accounts that should have been added were incorrectly subtracted. In other instances, the formula pulled information from the wrong FERC Form No. 1 line. Finally, there were instances where items specifically excluded by formula rate protocols were included in the formula rate. (FA15-6-000).
- Administrative and General (A&G) Expenses – Most audits find that public utilities recorded non-operating expenses and functional operating and maintenance expenses in A&G expense accounts, leading to inappropriate inclusion of such costs in revenue requirements produced by their formula rates. Examples of these costs include: employment discrimination settlement payments, lobbying expenses, charitable contributions, storm damage to distribution systems, and payments of penalties. (FA18-3-000, FA17-1-000).
- Unused Inventory and Equipment – Public utilities included in the cost of construction projects the cost of materials, supplies, and equipment purchased for the project, without removing the cost of items ultimately unused in whole or in part. (FA13-3-000).

**Transmission Rate Incentives.** The Commission has granted many public utilities transmission incentive rate treatments as a means of promoting and developing a more efficient and robust transmission system. Recent audit activity has found that effective procedures and controls were lacking to ensure full compliance with the conditions of Commission orders approving transmission incentive rate treatments. In particular, projects that did not qualify for the transmission incentive to include construction work in progress in rate base were inappropriately including it. DAA believes more robust procedures and controls to ensure compliance with the application of transmission incentive rate treatments could have prevented noncompliance in this area. (FA16-1-000).

**Open Access Transmission Tariffs (OATT).** An essential goal of open access is to support efficient and competitive markets. On recent OATT audits, DAA noted instances where company actions did not support this goal due to noncompliance with OATT terms and conditions. Specifically, DAA identified issues relating to improper use of network transmission service and secondary network transmission service (PA18-2-000), improper sales from designated network resources (PA17-7-000), transmission capacity not released in accordance with Commission-approved tariffs (PA13-4-000), inaccurate available transmission capacity data posted on the Open Access Same-Time Information System (OASIS) (PA17-7-000), and transmission service provided to customers under expired transmission service agreements (PA13-6-000).

**Data Reporting by ISO/RTO Market Participants.** In recent audits, DAA identified instances when market participants did not submit accurate data to the ISOs/RTOs (PA17-5-000, PA17-3-000, PA15-5-000). Inaccurate data submitted by market participants weakens the ISOs'/RTOs' ability to operate effective and efficient energy markets. For example, DAA identified instances when market participants submitted generation resource offers that did not reflect the actual known physical capabilities and characteristics of the resources. This affected the ability of the ISOs/RTOs to optimize dispatch in order to reflect the actual marginal cost of energy and to

manage transmission congestion. DAA encourages all market participants to have adequate controls in place to ensure accurate, complete, and timely data are submitted to the ISOs/RTOs.

**Natural Gas Accounting and Tariff Matters.** Natural gas audits have evaluated compliance with the Commission's accounting and FERC Form No. 2, Annual Report of Major Natural Gas Companies (FERC Form No. 2), reporting requirements to ensure that transparent and accurate data is reported for use by all stakeholders in developing and monitoring rates. The audits also covered the administration and application of transportation services and rates among customers in accordance with approved gas tariffs. In recent natural gas audits, DAA has found noncompliance in the following areas:

- Gas Tariff – Natural gas pipelines did not comply with FERC gas tariff procedures, specifically with regard to: (1) using the method specified in the tariff for valuing system gas activities (PA16-2-000, PA13-5-000); (2) enforcing stipulations in operational balancing agreements to manage and monitor gas imbalance activities between interstate and intrastate pipelines (PA16-4-000); (3) updating their tariffs to fully reflect the Commission's reservation charge crediting policy[36] for force majeure and non-force majeure events (PA16-4-000); and (4) penalty revenues collected from offending shippers and refunded to non-offending shippers (FA18-2-000).
- Accounting – Natural gas pipelines did not comply with Commission accounting requirements, specifically with regard to: certain activities pertaining to system gas accounting (PA16-2-000); penalty revenues assessed to noncompliant shippers (PA16-4-000, PA10-3-000); shipper imbalances and cash-outs (FA15-1-000, PA13-5-000, PA10-3-000); lost and unaccounted-for gas (FA15-1-000, PA16-4-000, PA13-5-000); and fuel used in compressor stations (FA15-1-000). Other common areas of noncompliance included: (1) use of AFUDC rates above the maximum allowed rate (PA16-4-000); (2) improper derivation of certain components included in the AFUDC rate (FA13-7-000); (3) accrual of AFUDC on unpaid amounts and non-eligible construction costs (FA13-9-000, FA12-4-000); (4) misclassification of non-operating expenses associated with donations, fines, and employment discrimination compromise settlements (FA15-16-000), or with penalties and lobbying activities (PA13-5-000, FA13-7-000, FA12-4-000), or membership dues (FA18-2-000); (5) misclassification of operating expenses as general and administrative expenses (PA16-2-000, PA16-4-000); (6) improper allocation of shared service costs (PA16-2-000); and (7) application of cost allocation methodologies absent a time study or other supporting records (PA16-2-000, FA15-16-000).
- Reporting – FERC Form No. 2 reporting was inaccurate, incomplete, and omitted required information and footnote disclosures required for various schedules supporting the financial reporting (FA18-2-000, FA17-6-000). Other reporting matters pertained to unfiled nonconforming service agreements and cash management agreements (FA17-6-000).

[36] *Natural Gas Supply Ass'n*, 135 FERC ¶ 61,055, *order on reh'g*, 137 FERC ¶ 61,051 (2011).

**Oil Pipelines (Page 700).** An essential part of oil pipeline audits is an examination of the accounting and operating data included on page 700 of the FERC Form No. 6, Annual Cost of Service-Based Analysis Schedule. This Schedule requires each oil pipeline company to report its total annual cost of service (as calculated under the Order No. 154-B methodology), operating revenues, and throughput in barrels and barrel-miles for the current and previous reporting year. The amounts reflected on page 700 represent only interstate service (i.e., FERC-jurisdictional) amounts, while the rest of the FERC Form No. 6 includes both interstate and intrastate amounts. The information reported on page 700 is used by the Commission and interested parties to evaluate interstate pipeline rates and facilitate the Commission's review of the five-year index.[37] Recent oil pipeline audits have identified accounting errors that impacted the accuracy of amounts reported on page 700, including: incorrect determination of interstate revenues and expenses and designating intrastate amounts as interstate (FA16-7-000); misclassification of carrier and noncarrier property, and of charitable donations, fines/penalties, lobbying activities, and affiliate transaction mark-ups as operating rather than non-operating expenses (FA16-6-000, FA16-7-000); and use of the consolidated rather than the equity method of accounting for investments in joint ventures and subsidiary companies (FA16-5-000). DAA also found that some companies were not conducting depreciation studies as required, leading to depreciation rates not aligning with the actual service lives of the plants, and ultimately to asset groups with negative book balances (FA16-5-000).

**Nuclear Decommissioning Trust Funds.** The Commission's regulations concerning nuclear decommissioning trust funds require public utilities owning nuclear power plants to file annual trust fund reports. Recent audits have identified public utilities that failed to submit annual decommissioning trust fund reports (PA13-5-000), or clearly distinguish Commission-jurisdictional from nonjurisdictional monies held in the funds, and accurately report the amount of Commission-jurisdictional money in the trusts (PA13-15-000, FA15-6-000. FA15-7-000).

**Consolidation.** Commission accounting regulations require the equity method of accounting for all investments in subsidiaries. Recent audits continued to find jurisdictional companies incorrectly using the consolidation method of accounting for subsidiaries instead of the equity method. As a result, improper amounts were included in formula rate billings (PA14-2-000). Entities must seek a waiver from the Commission to use the consolidation method for an investment in a subsidiary.

**Untimely Filing of Commission Reports.** DAA identified several companies that failed to timely file various reports with the Commission, including decommissioning trust fund reports and required filings, and reports related to mergers. Failure to timely file these reports prevents the Commission and industry from reviewing and using relevant data. It also negatively impacts

[37] Page 700 is used as a preliminary screening tool for shippers and other stakeholders to gauge whether an oil pipeline's cost of service substantially diverges from revenues generated by its rates. The Commission also uses the expense and barrel mile data from this page to support the Commission's determination of its proposed oil pipeline transportation rate index adjustment for a five-year, forward looking period. The next five-year index will be based on the Commission's evaluation of the increase in costs, on a dollar per barrel-mile basis from 2014 to 2019, as reflected on page 700 in oil pipelines' filings, and will become effective in 2021.

transparency and creates doubt regarding the effectiveness of these companies' compliance programs.

## D. Audit Matters

DAA's audits are public, risk-based, and cover a variety of audit scope areas. The entities selected for an audit are not typically suspected of any wrongdoing. DAA consults with other divisions within Enforcement and other Commission program offices to inform DAA's risk-based methodology for selecting audit scope areas and audit candidates. DAA is not limited in the types of audits it conducts; rather, it responds to the needs and priorities of the Commission and the industry. Individual audits may contain multiple and different scope areas, but every audit includes a review of the audited entity's internal compliance program.

DAA's public audit reports detail each audit's scope, methodology, findings of noncompliance, and corrective recommendations, with the expectation that all jurisdictional entities will use this information to be better informed, avoid noncompliance, and improve operational performance. Although not all audits result in findings of noncompliance, when they do, timely implementation of the audit report's corrective recommendations is expected. Timely implementation demonstrates an entity's commitment to improving compliance with the Commission's regulations and precedents and to reducing the risk of future noncompliance.

In FY2019, DAA completed 11 audits of public utility and natural gas companies covering a wide array of topics. The audits resulted in 76 findings of noncompliance, 286 recommendations for corrective action, and directed approximately $161.2 million in refunds and other recoveries. Specifically, DAA directed $11.8 million to be refunded to jurisdictional customers and prevented approximately $149.4 million from being inappropriately amortized and collected through future rates. These refunds and other recoveries addressed, among other subjects, the improper application of merger-related costs; lobbying, charitable donation, membership dues, and employment discrimination settlement costs; revenue credits; pending income tax and insurance premium refunds being treated as prepayments; and the regulatory AFUDC formula. Audit recommendations also directed improvements to the audited companies' internal accounting processes and procedures, financial reporting for accuracy and transparency, web site postings, and efficiency of operations. Collectively, these refunds and recommendations prevented unjust charges in jurisdictional rates, and provided procedural and process enhancements that benefit ratepayers and market participants. The audits summarized below were completed in FY2019 and provide a sample of DAA findings and results. Further

### Creating Greater Audit Efficiencies

In FY2019, DAA assigned its four audit branches to specific industry and audit coverage areas. Previously, DAA staff were assigned to various industries and audit coverage areas simultaneously. Now, each audit branch and its staff will focus on a specific industry and coverage area. The new branches are organized as follows: Electric (formula rates), Electric (other financial topics), Energy Markets, and Oil and Gas. This change was made to enable the branches and their staffs to develop greater expertise on the industries and topics they audit. In turn, this will translate into greater efficiency and effectiveness on each audit coverage area. DAA's other branches were not impacted by the realignment.

samples are contained in prior years' enforcement reports. The complete audit reports are publicly available in the Commission's eLibrary system.[38]

## 1. Formula Rates

**Black Hills Power Inc. (BHP) – Docket No. FA16-3-000.** At BHP, DAA evaluated compliance with: (1) the approved terms, rates, and conditions of BHP's transmission formula rate mechanism as provided in Attachment H of its Joint Open Access Transmission Tariff (Joint OATT); (2) the accounting requirements of the Uniform System of Accounts Prescribed for Public Utilities and Licensees in 18 C.F.R. Part 101 (Uniform System of Accounts (Public Utilities)); and (3) the reporting requirements of the FERC Form No. 1 under 18 C.F.R. § 141.1.[39] The audit identified six findings and 24 recommendations that required BHP to take corrective action. The six findings covered the following areas: (1) incorrect accounting for utility and nonutility operating income payroll taxes and improper inclusion of payroll taxes in BHP's transmission formula rate calculations; (2) prepaid annual software license renewal fees and prepaid maintenance costs that were recorded in Account 107, Construction Work in Progress (CWIP), rather than correct Account 165, Prepayments; (3) double counting litigation costs that flowed through formula rates to wholesale customers; (4) misclassifying various lobbying costs and merger-related consulting fees in expense accounts included in BHP's formula rate mechanism; (5) the inappropriate transfer of pension and benefit expenses into Account 253, Other Deferred Credits, instead of correct Account 228.3, Accumulated Provision for Pensions and Benefits; and (6) calculating the cost of long-term debt in a manner inconsistent with the Commission's regulations under 18 C.F.R. § 35.13(h)(22)(ii). As a result of the audit, BHP made refunds to wholesale transmission customers and revised its accounting policies and procedures in identified areas of noncompliance.

**Ohio Power Company (Ohio Power) – Docket No. FA17-2-000.** At Ohio Power, DAA evaluated compliance with: (1) the approved terms, rates, and conditions of Ohio Power's transmission formula rate mechanism as provided in Attachment H-14 of the PJM OATT, and other jurisdictional rates on file with the Commission; (2) the accounting requirements of the Uniform System of Accounts (Public Utilities) under 18 C.F.R. Part 101; and (3) the reporting requirements of the FERC Form No. 1 and the Supplemental Form 3-Q: Quarterly Financial Report (Supplemental Form 3-Q), under 18 C.F.R. § 141.1.[40] The audit identified four findings and 18 recommendations that required Ohio Power to take corrective action. The four findings covered the following areas: (1) understating revenue credits by excluding pole attachment revenue from revenue credit calculations; (2) not returning to transmission customers amounts collected in excess of Ohio Power's total investment in certain customer-funded projects; (3) treating as operating expenses various non-operating expenses relating to the servicing of accounts receivables sold to a third party on a non-recourse basis; and (4) not reporting certain required information on select pages of the FERC Form No. 1. As a result of the audit, Ohio Power made

[38] The Commission's eLibrary system can be accessed at www.ferc.gov/docs-filing/elibrary.asp.

[39] *Black Hills Power Inc.*, Docket No. FA16-3-000 (Dec. 14, 2018) (delegated letter order).

[40] *Ohio Power Co.,* Docket No. FA17-2-000 (Sept. 6, 2019) (delegated letter order).

refunds to wholesale transmission customers and updated its accounting policies and procedures in areas of noncompliance.

**Northern States Power Company (Minnesota) (NPSM) – Docket No. FA17-4-000.** At NSPM, DAA evaluated compliance with: (1) the approved terms, rates, and conditions of NSPM's transmission formula rate mechanism provided in Attachment O of MISO's FERC Electric Tariff, and other jurisdictional rates on file with the Commission; (2) the accounting requirements of the Uniform System of Accounts (Public Utilities) under 18 C.F.R. Part 101; (3) the reporting requirements of the FERC Form No. 1 and the Supplemental Form 3-Q, under 18 C.F.R. § 141.1; and (4) preservation of records requirements under 18 C.F.R. Part 125.[41] The audit identified six findings and 24 recommendations that require NSPM to take corrective action. The six findings covered the following areas: (1) recording an income tax receivable that represented a refund of a tax overpayment in Account 165, Prepayments, instead of Account 143, Other Accounts Receivable, resulting in an overstatement of rate base; (2) recording other costs (unspent contributions to joint venture trusts and estimated pending insurance premium refunds) as prepayments in Account 165 that did not qualify as prepayments; (3) the misclassification as operating expenses of certain costs that should be recorded in non-operating expense accounts, including settlement payments relating to employment discrimination claims, contrary to Accounting Release AR-12; (4) the improper recording of amounts relating to contingent liabilities in Account 282.2, Accumulated Provision for Injuries and Damage, without having obtained Commission permission; (5) the use of depreciation rates that had not been approved by the Commission; and (6) failing to follow a consistent capitalization policy for transmission insulators. As a result of the audit, NSPM was directed to submit refund analyses and make subsequent refunds with respect to findings 1 through 3, and update accounting practices and policies, correct journal entries, and submit a corrected FERC Form No. 1 with respect to particular areas of noncompliance identified in the audit report.

**Cleco Power LLC (Cleco Power) – Docket No. FA18-3-000.** At Cleco Power, DAA evaluated compliance with: (1) the tariff requirements governing Cleco Power's FERC jurisdictional rates, including its transmission formula rate mechanism in Attachment O of MISO's FERC Electric Tariff; (2) conditions established in the July 17, 2015 Commission Order authorizing a merger involving Cleco Power; (3) the accounting requirements of the Uniform System of Accounts (Public Utilities) under 18 C.F.R. Part 101; and (4) the reporting requirements of the FERC Form No. 1 under 18 C.F.R. § 141.[42] The audit identified 12 findings and 59 recommendations that required Cleco Power to take corrective action. The 12 findings covered the following areas: (1) improper computation of AFUDC by grossing up the return on equity rate and including undistributed subsidiary earnings in the equity balance; (2) improper exclusion of excess and deficient ADIT, created as a result of the 2017 Tax Cut and Jobs Act, from the wholesale transmission formula rate computation; (3) improper inclusion of merger-related internal labor costs and debt cancellation costs in wholesale transmission formula rate cost determinations; (4) improper inclusion of ADIT related to merger commitment costs in wholesale transmission

[41] *Northern States Power Company* (*Minnesota*), Docket No. FA17-4-000 (Aug. 29, 2019) (delegated letter order).

[42] *Cleco Power LLC*, Docket No. FA18-3-000 (Sept. 27, 2019) (delegated letter order).

formula rates; (5) recording of rent received from an affiliate in Account 455, Interdepartmental Rents, rather than correct Account 454, Rent from Electric Property, thereby understating revenue credits; (6) recording operating and maintenance costs associated with a renewable electric generation plant in Account 923, Outside Services Employed, instead of Account 553, Maintenance of Generating and Electric Equipment (Major Only); (7) recording the cost of a transmission asset not owned by Cleco Power in Account 353, Station Equipment, and including the cost in transmission formula rate computations; (8) recording compromise settlement payments relating to a discriminatory employment practice suit in Account 921, Office Supplies and Expenses, instead of Account 426.5, Other Deductions; (9) improperly including the cost of generation, distribution, and gas pipeline assets in the formula rate as Account 105, Electric Plant Held for Future Use, when Cleco Power's formula rate specified that items in Account 105 are only included in the computation of the wholesale transmission revenue requirement to the extent they are transmission-related costs; (10) improper accounting treatment of various non-operating or non-transmission expenses as A&G expenses or functional transmission expenses, including lobbying costs, charitable contributions, membership dues, and storm damage costs incurred on Cleco Power's distribution system; (11) recovery of regulatory assets for which Cleco Power had not obtained the necessary prior authorization from FERC; and (12) not reporting all required information in FERC Form No. 1 filings. As a result of the audit, Cleco Power was directed to submit refund analyses and make subsequent refunds with respect to findings 1 through 10. Other costs that were incorrectly accounted for in plant-in-service and similar accounts were reclassified to appropriate accounts to ensure proper treatment of the costs in the development of future rates. Cleco Power was also directed to update accounting practices and policies, correct journal entries, and update FERC Form No. 1 reporting practices with respect to particular areas of noncompliance identified in the audit report.

## 2. Gas Tariff & Accounting

**Northern Natural Gas Company (Northern Natural) – Docket No. PA16-2-000.** At Northern Natural, DAA evaluated compliance with: (1) selected provisions of Northern Natural's FERC Gas Tariff; (2) accounting regulations of the Uniform System of Accounts Prescribed for Natural Gas Companies (Uniform System of Accounts (Natural Gas)), under 18 C.F.R. Part 201; and (3) reporting requirements of the FERC Form No. 2, under 18 C.F.R. § 260.1.[43] The audit identified five findings and 15 recommendations that required Northern Natural to take corrective action. The five findings covered the following areas: (1) misclassifying certain labor costs averaging about $2.6 million annually as A&G expenses rather than O&M expenses, and between certain O&M expense accounts; (2) misallocating certain payroll costs and not assigning compressor electric costs to Northern Natural's market-based rate storage project; (3) not maintaining proper records to support payroll allocations to all O&M expense accounts; (4) not performing annual surveys and maintaining records to support the allocation of employee labor costs to construction overheads; and (5) misclassifying operational gas sales revenues and other related activities for system gas imbalance accounting purposes. As a result of the audit, Northern Natural committed to update its accounting procedures and practices in the areas of noncompliance, and make

[43] *Northern Natural Gas Co.,* Docket No. PA16-2-000 (May 14, 2019) (delegated letter order).

corrections in its next FERC Form No. 2 filing to rectify certain affected account balances and statements.

**Trunkline Gas Company (Trunkline) – Docket No. PA16-4-000.** At Trunkline, DAA evaluated compliance with: (1) select portions of Trunkline's FERC Gas Tariff; (2) the Uniform System of Accounts (Natural Gas), under 18 C.F.R. Part 201; and (3) the reporting requirements of the FERC Form No. 2, under 18 C.F.R. § 260.1.[44] The audit identified ten findings and made 28 recommendations that required Trunkline to take corrective action. The ten findings covered the following areas: (1) absence of a tariff provision for reservation charge credits to shippers with firm service affected by force majeure and non-force majeure events, and the improper inclusion of maintenance activities in the tariff's force majeure definition; (2) tariff language not consistent with the Commission's requirement that all interconnecting pipelines enter into Operational Balancing Agreements (OBAs), and inconsistencies between the administration and management of imbalances and the terms of Trunkline's Tariff and standard OBA; (3) misreporting gas equivalents in annual fuel reimbursement filings in a manner that did not impact the accuracy of the fuel reimbursement rate charges but reduced the transparency of the gas equivalents reported in the deferred fuel reimbursement account component schedule; (4) recording cash management and affiliate transactions carried for less than a year as long-term investments or cash advances rather than short-term receivables or payables; (5) incorrectly applying an AFUDC rate that exceeded the rate of return reflected in Trunkline's recourse rates and that did not take into account the effects of Trunkline's cash management program on its AFUDC rate calculation; (6) classifying labor and other system gas control employee costs as A&G expenses rather than transmission operating expenses, and treating general supervision costs associated with underground storage facilities as transmission, rather than storage, operating expenses; (7) accounting for penalty revenues collected from offending shippers and refunded to non-offending shippers in Account 142, Customer Accounts Receivable, and Account 242, Miscellaneous Current and Accrued Liabilities, rather than Account 495, Other Gas Revenues, and Account 254, Other Regulatory Liabilities; (8) incorrectly accounting for lost-and-unaccounted-for fuel (LAUF) as compressor fuel, rather than in accounts designated for system gas losses; (9) not timely removing from Trunkline's books certain assets and a regulatory liability for an asset retirement obligation (ARO) associated with facilities Trunkline had sold; and (10) recording incorrect volumes in Account 808.1, Gas Withdrawn from Storage-Debit, and Account 808.2, Gas Delivered to Storage-Credit. As a result of the audit, Trunkline updated its accounting policies and procedures in areas of noncompliance, submitted corrected FERC Form No. 2s, and removed from its plant or operating expense accounts certain improperly recorded expenses.

**Transcontinental Gas Pipe Line Company (Transco) – Docket No. FA18-2-000.** At Transco, DAA evaluated compliance with: (1) selected provisions of Transco's FERC Gas Tariff; (2) accounting regulations of the Uniform System of Accounts (Natural Gas), under 18 C.F.R. Part 201; and (3) reporting requirements of the FERC Form No. 2, under 18 C.F.R. § 260.1.[45] The audit identified ten findings and 31 recommendations that required Transco to take corrective

[44] *Trunkline Gas Co.*, Docket No. PA16-4-000 (Oct. 19, 2018) (delegated letter order).

[45] *Transcontinental Gas Pipe Line Co.,* Docket No. FA18-2-000 (June 25, 2019) (delegated letter order).

action. The ten findings covered the following areas: (1) capitalizing as plant the cost of replacing minor items of property rather than recording the cost in maintenance accounts; (2) improperly accounting for allocated direct and indirect overhead operating expenses; (3) accounting for allocated direct and indirect overhead *non-operating* expenses, such as charitable contributions, advertising expenses, and lobbying and political expenses, in utility plant and operating expense accounts rather than non-operating expense accounts; (4) improperly including the cost of unused materials in Account 106, Completed Construction Not Classified; (5) improperly including undistributed subsidiary earnings, accumulated other comprehensive income, and unamortized discounts on long-term debt in the equity and long-term debt balances when computing the AFUDC rate; (6) improperly accounting for feasibility evaluation costs on contemplated construction in a manner that overstated expenses in some periods, and understated them in others, in FERC Form No. 2 filings; (7) reporting expenses in FERC Form No. 2 relating to incremental rate facilities in an inaccurate manner; (8) a lack of required information in FERC Form No. 2 filings; (9) distributing penalty revenues to the shippers that caused the penalties, thereby reducing the amount of penalty revenues that should have gone to non-offending shippers, and not properly accounting for the regulatory liabilities associated with the penalty revenue collected; and (10) adding required reservation charge crediting provisions to three firm storage rate schedules in Transco's FERC Gas Tariff. As a result of the audit, Transco submitted proposed revised accounting entries and FERC Form No. 2 entries in the areas of noncompliance, thereby preventing amounts from potentially being inappropriately collected through future rates, and developed revised accounting policies and practices in the areas of noncompliance.

**Equitrans, L.P. (Equitrans) – Docket No. FA17-6-000.** At Equitrans, DAA evaluated compliance with: (1) selected provisions of Equitrans' FERC Gas Tariff; (2) accounting regulations of the Uniform System of Accounts (Natural Gas), under 18 C.F.R. Part 201; and (3) reporting requirements of the FERC Form No. 2, under 18 C.F.R. § 260.1.[46] The audit identified eight findings and 28 recommendations that required Equitrans to take corrective action. The eight findings covered the following areas: (1) the inappropriate inclusion of *unpaid* contract retention accruals in the calculation of AFUDC; (2) the incorrect inclusion of approximately $1.3 million of unused construction materials in construction work orders, CWIP, and ultimately plant-in-service, which also resulted in the overstatement of AFUDC; (3) accounting for an income tax receivable that represented a refund for an overpayment in Account 165, Prepayments, rather than Account 146, Accounts Receivable from Associated Companies; (4) recording non-operating expenses, such as charitable donations, penalties, and nonutility expenses, in plant cost accounts and operating expense accounts; (5) recording assets in Account 105, Plant Held for Future Use, when there was no definite plan for their future use in gas service, instead of Account 121, Nonutility Property; (6) failing to file two nonconforming interruptible gathering service agreements with the Commission; (7) not filing Equitrans' effective cash management agreement with the Commission as required by 18 C.F.R. § 260.400; and (8) not including certain required information in its FERC Form No. 2 filings. As a result of the audit, Equitrans submitted proposed revised accounting entries and revised FERC Form No. 2 entries relating to areas of noncompliance, thereby preventing amounts from potentially being inappropriately collected through future rates, and developed revised accounting policies and practices in the areas of noncompliance.

[46] *Equitrans, L.P.,* Docket No. FA17-6-000 (Oct. 19, 2019) (delegated letter order).

## 3. Electric Tariff & Accounting

**Avista Corporation (Avista) – Docket No. PA18-2-000.** At Avista, DAA evaluated compliance with: (1) the terms, conditions, and rates of Avista's OATT; (2) the accounting requirements of the Uniform System of Accounts (Public Utilities), under 18 C.F.R. Part 101; (3) the reporting requirements of the FERC Form No. 1 and the Supplemental Form 3-Q, under 18 C.F.R. § 141.1; and (4) the regulations regarding OASIS platforms prescribed in 18 C.F.R. Part 37.[47] The audit identified six findings of noncompliance and made 23 recommendations for corrective action. The six findings covered the following areas: (1) improper reservation of hourly secondary network transmission service to support off-system sales to non-network customers; (2) when computing AFUDC, improperly including undistributed subsidiary earnings in the equity component; including Account 219, Accumulated Other Comprehensive Income, in the equity component; using monthly (instead of the required prior-year-end) balances to compute equity and long-term debt; excluding Account 234, Notes Payable to Associated Companies, from the short-term debt component; and accounting for the excess AFUDC accrual arising from higher state-approved versus Commission-approved AFUDC rates as a cost of plant rather than a regulatory asset in Account 182.3; (3) improper accounting for deferred income taxes relating to the equity component of the AFUDC rate; (4) when removing approximately $2.8 million of system planning costs improperly capitalized as CWIP, failing to remove the cost of plant amounts relating to AFUDC, the accumulated provision for depreciation, and current and deferred income taxes that stemmed from the improper capitalization; (5) improperly accounting for certain items related to its Asset Retirement Obligations; and (6) failing to comply with the instructions on Page 398, Purchase and Sale of Ancillary Services, in its FERC Form No. 1 filings. The Avista audit also identified an additional matter regarding Avista's use of Transmission Service Numbers. As a result of the audit, Avista was prevented from potentially recovering amounts inappropriately included in AFUDC or otherwise capitalized, and updated its accounting policies and practices in areas of noncompliance.

**American Electric Power Company, Inc. (AEP) – Docket No. FA17-1-000.** At AEP, DAA evaluated compliance with: (1) cross-subsidization restrictions on affiliate transactions under 18 C.F.R. Part 35; (2) accounting, recordkeeping, and reporting requirements under 18 C.F.R. Part 366; (3) the Uniform System of Accounts For Centralized Service Companies under 18 C.F.R. Part 367; (4) preservation of records requirements for holding companies and service companies under 18 C.F.R. Part 368; and (5) FERC Form No. 60, Annual Report of Centralized Service Companies (FERC Form No. 60), requirements under 18 C.F.R. Part 369. The audit also evaluated the associated public utilities' transactions with affiliated companies for compliance with the Commission's accounting requirements under the Uniform System of Accounts (Public Utilities), under 18 C.F.R. Part 101, the applicable reporting requirements in the FERC Form No. 1, under 18 C.F.R. Part 141, and jurisdictional rates on file.[48] The audit identified four findings and made 22 recommendations requiring corrective action. The findings addressed the following areas: (1) when calculating AFUDC, certain AEP jurisdictional utilities improperly included Account 219,

[47] *Avista Corp.,* Docket No. PA18-2-000 (Sept. 19, 2019) (delegated letter order).

[48] *American Electric Power Company, Inc*., Docket No. FA17-1-000 (Apr. 23, 2019) (delegated letter order).

Accumulated Other Comprehensive Income, as part of the equity component, and multiple AEP jurisdictional utilities improperly computed AFUDC rates on a monthly basis; (2) AEP improperly included approximately $295,000 of merger-related transition costs in formula rate determinations and wholesale transmission customer bills; (3) AEP recorded charitable contributions and a penalty payment in various A&G and operation and maintenance (O&M) expense accounts, instead of using the appropriate *non-operating* expense accounts; and (4) various A&G labor, membership dues, outside services, and advertising expenses were misclassified. As a result of the audit, AEP or its jurisdictional utility subsidiaries made refunds to wholesale customers, updated accounting policies and practices in areas of noncompliance, and reclassified amounts that otherwise might have been improperly used in the development of future rates.

**Xcel Energy Inc. (Xcel) – Docket No. FA17-4-000.** At Xcel, DAA evaluated compliance with: (1) cross-subsidization restrictions on affiliate transactions under 18 C.F.R. Part 35; (2) accounting, recordkeeping, and reporting requirements under 18 C.F.R. Part 366; (3) preservation of records requirements for holding companies and service companies under 18 C.F.R. Part 368; and (4) the Uniform System of Accounts for Centralized Service Companies under 18 C.F.R. Part 367. The audit also evaluated the associated public utilities' compliance with the Commission's accounting requirements for transactions with associated companies under the Uniform System of Accounts (Public Utilities), under 18 C.F.R. Part 101 and the applicable reporting requirements in the FERC Form No. 1, under 18 C.F.R. Part 141.[49] The audit identified five findings and made 14 recommendations requiring corrective action. The findings addressed the following areas: (1) Xcel's centralized service company, Xcel Energy Services Inc. (XES), allocated capital costs of corporate software only to the Xcel public utilities, but such capital costs should have been allocated to all Xcel companies benefiting from XES' use of the software, as required by 18 C.F.R. § 376.11; (2) XES incorrectly calculated a cost allocation method used on shared costs for operation, maintenance, and management of the Xcel companies' information technology network; (3) XES allocated income tax expense only to the Xcel public utilities, but such expense should have been allocated to all Xcel companies that caused Xcel to incur income tax liabilities, per the requirements of 18 C.F.R. § 376.11; (4) payments relating to settlement of employment discrimination claims were recorded in operating expense accounts, instead of Account 426.5, Other Deductions, as required by Accounting Release AR-12, and the expenses were passed through to wholesale transmission customers; and (5) XES did not disclose all allocation methodologies that it used to assign costs in its FERC Form No. 60 filings. As a result of the audit, Xcel was directed to submit refund analyses relating to the areas of noncompliance, and update its accounting and FERC Form No. 60 procedures and policies.

## E. Pending Contested Audit Matters

**Dominion Energy Transmission, Inc. (DETI) – FA15-16-000.** At DETI, DAA evaluated compliance with: (1) its FERC Gas tariff; (2) the accounting requirements of the Uniform System of Accounts (Natural Gas), under 18 C.F.R. Part 201; and (3) the reporting requirements of the

[49] *Xcel Energy Inc.,* Docket No. FA17-4-000 (Aug. 29, 2019) (delegated letter order).

FERC Form No. 2, under 18 C.F.R. § 260.1.[50] The audit identified six findings and 24 recommendations that required DETI to take corrective action. On September 27, 2017, DETI notified DAA that it accepted five of the six findings and intended to contest one finding. As a result of the accepted findings, incorrectly accounted for were reclassified to accounts not used in the development of future cost of service rates.

On December 8, 2017, DETI formally contested the Audit Report's finding that DETI did not use its own book balances and cost rates associated with its debt, equity, and CWIP to compute its AFUDC rate as required by the Commission's accounting requirements. DETI elected to have a paper hearing under the procedures in 18 C.F.R. Part 158. Initial and reply memoranda have been filed by interested entities. This matter is pending before the Commission.

## F. Accounting Matters

DAA administers the Commission's accounting programs established for the electric, natural gas, and oil industries, which are vital components of the Commission's strategy of setting just and reasonable cost-of-service rates. The foundation of the Commission's accounting programs is the Uniform System of Accounts codified in the Commission's regulations for public utilities and licensees, centralized service companies, natural gas companies, and oil pipeline companies. In addition, the Commission issues accounting rulings relating to specific transactions and applications through orders and Chief Accountant guidance letters based upon a consistent application of the uniform systems of accounts. This body of accounting regulations, orders, and guidance letters comprises the Commission's accounting requirements and promotes consistent, transparent, and decision-useful accounting information for the Commission and other stakeholders to set and monitor cost-of-service rates. DAA enables the Commission to achieve this strategic goal through careful consideration of the Commission's ratemaking policies, past Commission actions, industry trends, and external factors (e.g., economic, environmental, and technological changes, and mandates from other regulatory bodies) that impact the industries under the Commission's jurisdiction.

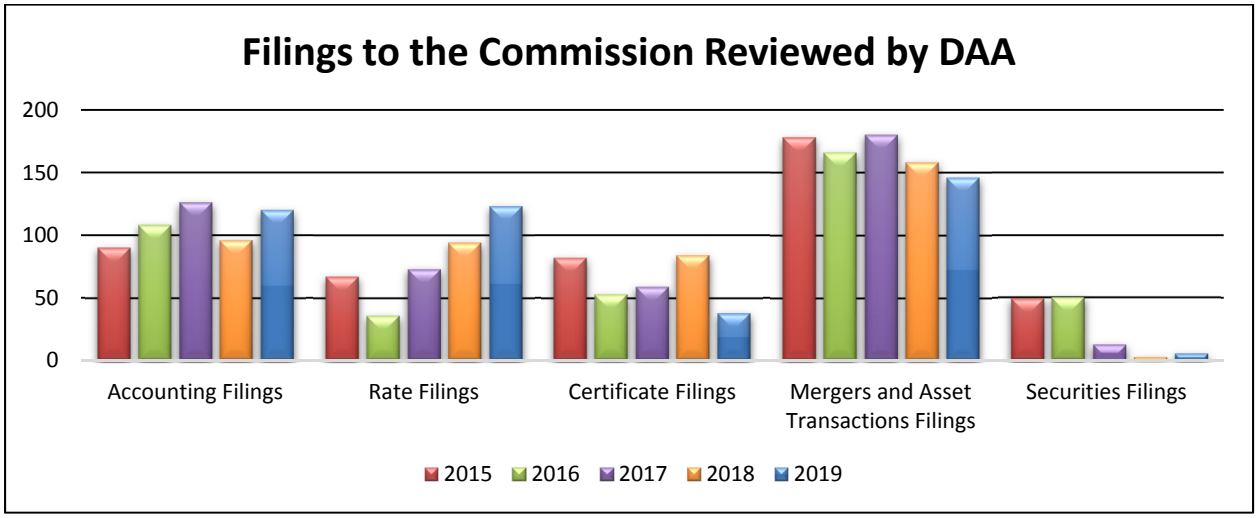
A substantial part of DAA's accounting workload involves coordination across various Commission program offices to provide regulatory accounting input and analysis on various types of filings made by jurisdictional entities. In addition, DAA provides accounting expertise to Commission program offices in developing Commission policies and rulemakings to ensure these initiatives fully consider and evaluate accounting and financial issues affecting jurisdictional entities. DAA also holds pre-filing meetings with jurisdictional entities seeking to make filings with the Commission to inform them of relevant accounting requirements. To better serve the Commission and other stakeholders in these capacities, DAA monitors and participates in projects initiated by the Financial Accounting Standards Board (FASB), Securities and Exchange Commission, and International Accounting Standards Board to address issues that may impact the Commission or its jurisdictional entities.

[50] *Dominion Energy Transmission, Inc.*, Docket No. FA15-16-000 (Nov. 8, 2017) (delegated letter order).

DAA also receives accounting inquiries and provides informal feedback on the Commission's accounting and financial reporting regulations. These inquiries come directly from jurisdictional entities, industry trade groups, legal and consulting firms, and other industry stakeholders, as well as through the Commission's Compliance Help Desk, Office of External Affairs (OEA), Enforcement Hotline, and other Commission program offices. DAA encourages jurisdictional entities to also seek formal guidance on accounting issues of doubtful interpretation to ensure compliance with the Commission's accounting and financial reporting regulations. Finally, a critical part of DAA's workload includes educating regulated entities and promoting compliance with the Commission's regulations through participation in various formal speaking engagements and industry accounting meetings.

## 1. Overview of FY2019 Filings Reviewed by DAA

In FY2019, DAA advised and acted on 433 proceedings at the Commission covering various accounting matters with cost-of-service rate implications, such as accounting for mergers and divestitures, asset transactions, early plant retirements, AFUDC, pensions and other post-retirement benefits, and income taxes. These proceedings included petitions for declaratory orders, natural gas certificate applications, merger and acquisition applications, electric and natural gas rate filings, applications for issuance of securities, and requests for accounting approval. In many of these cases, DAA served in an advisory role, identifying and analyzing the accounting implications of those requests. Over the past five years, DAA has reviewed over 2,000 Commission proceedings to ensure proper accounting is followed and to advise the Commission of potential rate impacts related to accounting decisions.




## 2. Requests for Approval of the Chief Accountant

In FY2019, DAA took action under the Chief Accountant's delegated authority on 120 accounting filings requesting approval of a proposed accounting treatment or financial reporting matter.[51] These filings raised various issues related to the Commission's accounting and financial

[51] The accounting filings are docketed in the Commission's eLibrary with the "AC" docket prefix (AC Dockets).

reporting requirements for electric, natural gas, and oil pipeline entities. Of note in FY2019, there was a continued high volume of accounting filings related to asset acquisitions, similar to FY2018. There was also a notable increase in the number of filings related to deferral of early plant retirement costs in regulatory accounts in response to applications by jurisdictional entities to recover those stranded costs in rates. The stranded costs, upon approval by the Chief Accountant, are held in regulatory accounts and amortized in concert with the period of rate recovery approved by the rate regulator.

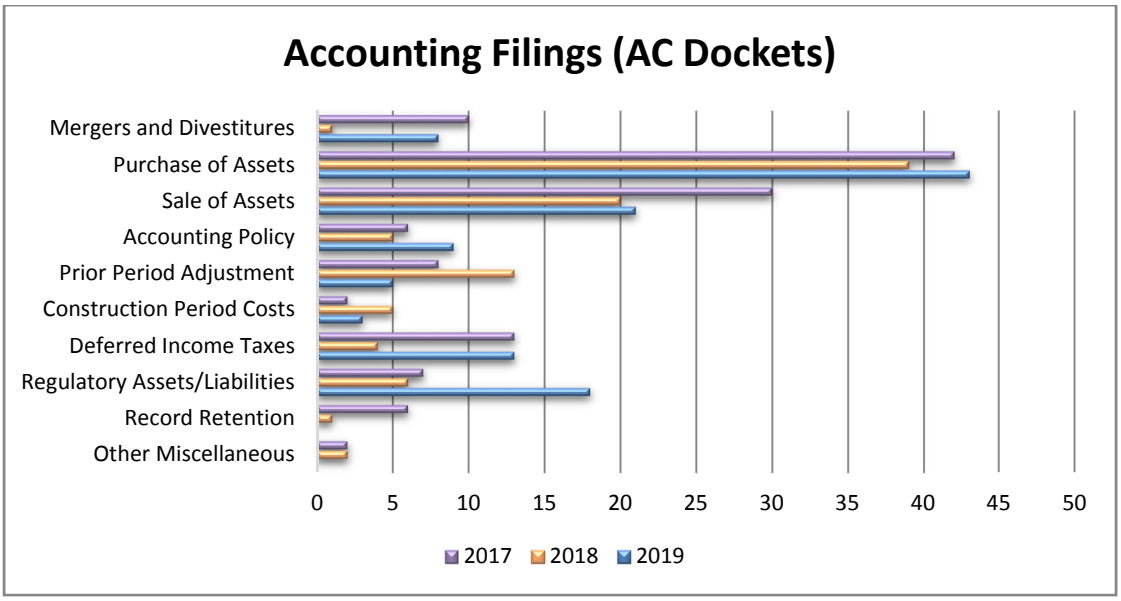
The Chief Accountant also issued a number of orders approving the proposed accounting for certain Account Standards Updates (ASU) and new Accounting Standards Codifications (ASC) issued by the FASB. The areas affected by the ASUs during FY2019 included changes in the fair value of equity instruments previously recorded in accumulated other comprehensive income (ASU 2016-01),[52] changes to revenue recognition of contracts with customers (ASC 606),[53] and the stranded tax effects of the Tax Cuts and Jobs Act of 2017 (TCJA) within accumulated other comprehensive income (ASU 2018-02).[54] The orders pertaining to ASU 2018-02 are further discussed below with other accounting issuances related to the TCJA.

When jurisdictional entities would like to make changes or corrections in accounting that require a prior period adjustment and may affect their regulatory accounting, the Commission's regulations require them to file a request with the Commission and receive approval before using Account 439, Adjustments to Retained Earnings, for public utilities and licensees, centralized service companies, and natural gas companies, and Account 705, Prior Period Adjustments to Beginning Retained Income Account, for oil pipeline companies. In reviewing these filings, DAA staff considers the changes to retained earnings as a result of the prior period adjustments and their effects on each entity's capital structure. In FY2019, the Chief Accountant considered 10 of these filings, concluded that the requested prior period adjustments were adequately supported, and issued letter orders approving the requests. The Chief Accountant letter orders also noted that the approval is not intended to influence the outcome of any rate treatment established for the accounting adjustments. DAA encourages companies making similar filings to include all relevant historical evidence and analyses to support the proposed adjustments.

[52] *See* FASB Accounting Standards Update No. 2016-01, Recognition and Measurement of Financial Assets and Financial Liabilities (January 2016).

[53] *See* FASB Accounting Standards Codification Topic 606, Revenue from Contracts with Customers.

[54] *See* FASB Accounting Standards Update No. 2018-02, Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income (February 2018).




## 3. Rate Proceedings

In FY2019, DAA participated in 123 rate proceedings that continued predominately to involve electric formula rate proceedings, but also included natural gas and oil rate proceedings. DAA worked with other Commission program offices to make recommendations related to accounting and financial issues and their effects on rates. Since many electric and natural gas rates are derived from accounting information in FERC Form Nos. 1 and 2, DAA sought to ensure that accounting information in rate proceedings was computed and presented consistently with the Commission's requirements. DAA also worked with other Commission program offices to enhance the transparency of financial information affecting formula rates so that all stakeholders have an opportunity to review the costs included in rates. Recurring areas of emphasis in DAA's rate filing reviews during FY2019 included stranded costs associated with early plant retirements, asset retirement obligations, pensions and post-retirement benefits other than pensions, and allocation of expenses to production, transmission, and distribution.

## 4. Certificate Proceedings

In FY2019, DAA reviewed 38 natural gas pipeline certificate applications seeking various authorizations, including to: (1) construct, own, and operate new pipeline facilities; (2) acquire pipeline facilities; (3) abandon pipeline facilities in place, by removal, or by sale; and (4) establish initial recourse rates for new pipeline service. DAA continued to assist other Commission program offices in the development of just and reasonable rates by reviewing construction costs and other items used to determine initial recourse rates, including O&M expenses, depreciation, taxes, and overall rate of return. In reviewing such information during FY2019, DAA continued to focus on whether applicants followed Commission accounting requirements related to asset abandonment, construction, AFUDC, contributions in aid of construction, regulatory assets and liabilities, leases, and system gas.

## 5. Merger and Acquisition Proceedings

In FY2019, DAA reviewed four merger and divestiture applications and approximately 143 asset acquisition and sales applications from public utilities under section 203 of the Federal Power Act (FPA). The accounting review for merger transactions entails examining proposed accounting for costs to execute the transaction, costs to achieve integration and synergies, purchase accounting adjustments to assets and liabilities, and goodwill. DAA also examines whether the accounting is consistent with any hold-harmless or other rate requirements discussed in a merger order. For asset acquisition transactions, staff conducts accounting reviews to examine whether applicants properly accounted for the purchase and sale of plant assets consistent with Commission regulations. The review focuses on whether jurisdictional entities maintained the appropriate original cost and historical accumulated depreciation of acquired utility plant and properly recorded acquisition premiums or discounts. DAA also reviewed merger and acquisition accounting entries to determine whether they provided enough transparency to the Commission and all interested parties to evaluate the impact on rates. DAA also consistently reminded jurisdictional entities to file accounting entries timely, within six months of a finalized merger or asset transaction, in accordance with Electric Plant Instruction No. 5 and the requirements of Account No. 102, Electric Plant Purchased or Sold.

## 6. Debt and Security Issuance Proceedings

In FY2019, DAA reviewed six public utility security issuance applications. Section 204(a) of the FPA requires jurisdictional entities to receive Commission authorization before issuing securities or assuming liabilities as guarantor, endorser, surety, or otherwise in respect of any security of another person. In reviewing these filings, the Commission evaluates an applicant's viability based on a review of financial statements submitted with the application, the applicant's interest coverage ratio, debt maturities, and cash-flow projections. DAA's review of debt and security applications provides critical analysis that helps prevent public utilities from borrowing excessive amounts of money and inappropriately using the proceeds to finance nonutility businesses without demonstration of the ability for repayment. This also ensures that future issuances of debt are consistent with the public interest.

## 7. Accounting Inquiries

In FY2019, DAA responded to 74 accounting inquiries from jurisdictional entities and other stakeholders on various accounting and financial topics. Accounting inquiries are made through the Compliance Help Desk, the Accounting Inquiries phone line and email, or directly to DAA staff. A large number of accounting inquiries during FY2019 sought accounting and financial reporting direction on capitalization of various costs, taxes, and functional classifications of electric plant. DAA responds to such accounting inquiries by providing informal accounting and financial reporting guidance based on Commission precedent and regulations, in addition to instructing individuals on how to find documents and regulations using the Commission's eLibrary system and Title 18 of the Code of Federal Regulations available electronically. Such informal accounting and financial reporting guidance is not binding on the Commission, and does not grant waiver of a Commission regulation or order.

## 8. Accounting for the Tax Cuts and Jobs Act of 2017 (TCJA)

On November 15, 2018, the Commission issued a policy statement in Docket No. PL19-2-000 to discuss certain rate and accounting implications resulting from the TCJA.[55] Specifically, the Commission required that public utilities and natural gas pipelines record excess and deficient Accumulated Deferred Income Taxes (ADIT) in Account 254, Other Regulatory Liabilities, and Account 182.3, Other Regulatory Assets, respectively. The excess and deficient ADIT should then be amortized consistent with the manner in which such amounts are reflected in rates using Account 410.1, Provision for Deferred Income Taxes, Utility Operating Income, and Account 411.1, Provision for Deferred Income Taxes – Credit, Utility Operating Income. The policy statement also clarified that for public utilities and natural gas pipelines, the balances of excess and deficient ADIT should continue to be recognized as regulatory liabilities and assets after an asset sale, in cases where the excess and deficient ADIT do not transfer to the purchaser of the asset. Similarly, public utilities and natural gas companies should continue to account for excess and deficient ADIT related to retirements as regulatory liabilities and assets.

Separately, the Chief Accountant issued numerous letters of approval during FY2019 for requests to reclassify the deferred tax effects stranded in Accumulated Other Comprehensive Income (AOCI) as a result of the TCJA's impact on retained earnings. This reclassification was necessary because other comprehensive income is accounted for net of tax, including any deferred tax effects. When items are realized and transferred from AOCI to income, the income tax effects are recognized at current tax rates. The TCJA created a discord between those items already recognized net of tax in AOCI using the previous tax rates and the eventual tax recognition in income using the new tax rates. This difference is considered stranded in AOCI. In order to remove these stranded amounts from AOCI, regulated entities have requested approval to move these amounts directly into retained earnings. This treatment is consistent with the allowed accounting treatment by the FASB under ASU 2018-02.

## 9. Accounting for Leases

On December 27, 2018, the Chief Accountant issued accounting guidance in Docket No. AI19-1-000 relating to the accounting for leases. The accounting guidance was issued in response to multiple inquiries from jurisdictional entities and other regulatory bodies regarding whether and how the Commission would implement ASC 842 issued by FASB. Prior to ASC 842, under generally accepted accounting principles, leases were classified either as operating leases, which did not recognize any assets or liabilities on the balance sheet, or capital leases, which recognized leased assets and lease obligations on the balance sheet. The criteria for classifying a lease as a capital lease depended on whether at least one of four criteria were met. If any one of those criteria were met, the lease was considered a capital lease. ASC 842 changed the nomenclature of the two classes of leases to operating leases and finance leases. While the requirement to meet at least one of four criteria to classify a lease as a finance lease is similar to that previously used for capital leases (i.e., the distinction between an operating lease and a capital lease is similar to the distinction between an operating lease and a finance lease), there was a significant change to accounting for

[55] *Accounting and Ratemaking Treatment of Accumulated Deferred Income Taxes and Treatment Following the Sale or Retirement of an Asset*, Docket No. PL19-2-000 (Nov. 15, 2018).

operating leases. Under ASC 842, all leases, including operating leases, require recognition of assets and liabilities on the balance sheet if the lease term is over 12 months. With this change, most companies will now reflect much larger balance sheets than those prior to ASC 842.

The Chief Accountant guidance letter clarified that under the Commission's accounting requirements, jurisdictional entities may also recognize assets and liabilities on the balance sheet for operating leases consistent with ASC 842. However, while ASC 842 requires the presentation of operating leases and finance leases separately on the balance sheet, the Chief Accountant explained that the Uniform System of Accounts only provides one account for leased assets (Account 101.1, Property under Capital Leases). Similarly, the Uniform System of Accounts only provides one account for the current portion of lease liabilities (Account 243, Obligations under Capital Leases–Current) and one account for the long-term portion of lease liabilities (Account 227, Obligations under Capital Leases–Noncurrent). Accordingly, both operating leases and finance leases on the balance sheet must be accounted for under the same lease asset and lease liability accounts. Another difference between lease accounting under ASC 842 and lease accounting under the Commission's accounting requirements is whether to recognize land rights as a lease. Under ASC 842, certain easements are considered leases, while the Uniform System of Accounts requires all land rights to be recognized as part of utility plant in service.

Staff notes that changes in accounting by the FASB, such as ASC 842, are not to be construed as a change to, or a waiver of, the Commission's accounting requirements. When necessary, the Chief Accountant or the Commission will issue guidance on the implementation of changes in accounting standards issued by the FASB.

## 10. International Financial Reporting Standards

DAA continued its participation with the International Financial Reporting Standards (IFRS) Foundation, the International Accounting Standards Board (IASB), and their project on Rate-Regulated Activities (RRA), which remains of special interest to the Commission and its regulated entities. In FY2019, the Chief Accountant, as a Consultative Group member for the RRA Project, participated in informal and formal meetings with U.S. regulated entities, state commissions, and international regulators to inform the development of an IFRS accounting standard that provides for regulatory assets and liabilities in IFRS financial statements. During this period, the IASB has begun to develop an accounting model for recognizing regulatory assets and liabilities on IFRS financial statements, and is expected to issue an exposure draft for comments during the first half of calendar year 2020. In FY2020, the Chief Accountant stands ready to continue providing expert advice to IASB staff regarding the development of permanent standards on rate-regulated activities.

# DIVISION OF ANALYTICS AND SURVEILLANCE

## A. Overview

The Division of Analytics and Surveillance (DAS) develops surveillance tools, conducts surveillance, and analyzes transactional and market data to detect potential manipulation, anticompetitive behavior, and other anomalous activities in the energy markets. DAS focuses on: (1) natural gas surveillance; (2) electric surveillance; and (3) analytics for reviewing market participant behavior. The analysts and economists in DAS identify market participants whose conduct potentially calls for investigation. They do this not only by conducting surveillance and inquiries of the natural gas and electric markets, but also by reviewing market monitor referrals[56] and Hotline complaints against the non-public data available to the Commission. This internal review process reduces burden on the industry, by resolving some matters without the need for investigation. When an investigation is opened, DAS staff participates in investigations with attorneys from DOI, providing detailed transactional analysis, market event analysis, and subject matter expertise.

To perform these functions, access to high quality, relevant, and timely data is essential. Since the creation of DAS in 2012, the Commission has been enhancing its data collection through orders, agreements, and subscription services in a manner designed to minimize burden on market participants. In Order No. 760, the Commission directed the ISOs/RTOs to provide, on an ongoing basis and in a format consistent with how the data is collected in each market, critical information on market bids, offers, and market outcomes.[57] On average, the Commission receives, on a non-public basis, approximately seven gigabytes of data in more than 1,350 tables each day from the six organized markets combined. Each ISO/RTO database is different, and DAS is responsible for understanding the particular nuances of each database and preparing them for use in surveillance screens and analyses.

Similarly, pursuant to Order No. 771,[58] the Commission gained access to the electronic tags (eTags) used to schedule the transmission of electric power interchange transactions in jurisdictional wholesale markets by requiring that each covered eTag identify the Commission as a party authorized to review its contents. The Commission has access to approximately 7.6 million eTags and gains access to approximately 5,000 new eTags each day. The Commission also routinely receives non-public physical electric and natural gas market data from the Intercontinental Exchange (ICE) and a subset of the Large Trader Report from the Commodity Futures Trading Commission (CFTC) through a Memorandum of Understanding. DAS staff

[56] Specific examples of this review of market monitor referrals are included in DOI Section F.2. of this report under "Illustrative MMU Referrals Closed with No Action."

[57] *Enhancement of Electricity Market Surveillance and Analysis through Ongoing Electronic Delivery of Data from Regional Transmission Organizations and Independent System Operators*, Order No. 760, 139 FERC ¶ 61,053 (2012).

[58] *Availability of E-Tag Information to Commission Staff*, Order No. 771, 141 FERC ¶ 61,235 (2012).

continue to use these data sources, EQR data, and data from a variety of subscription-based services, extensively.

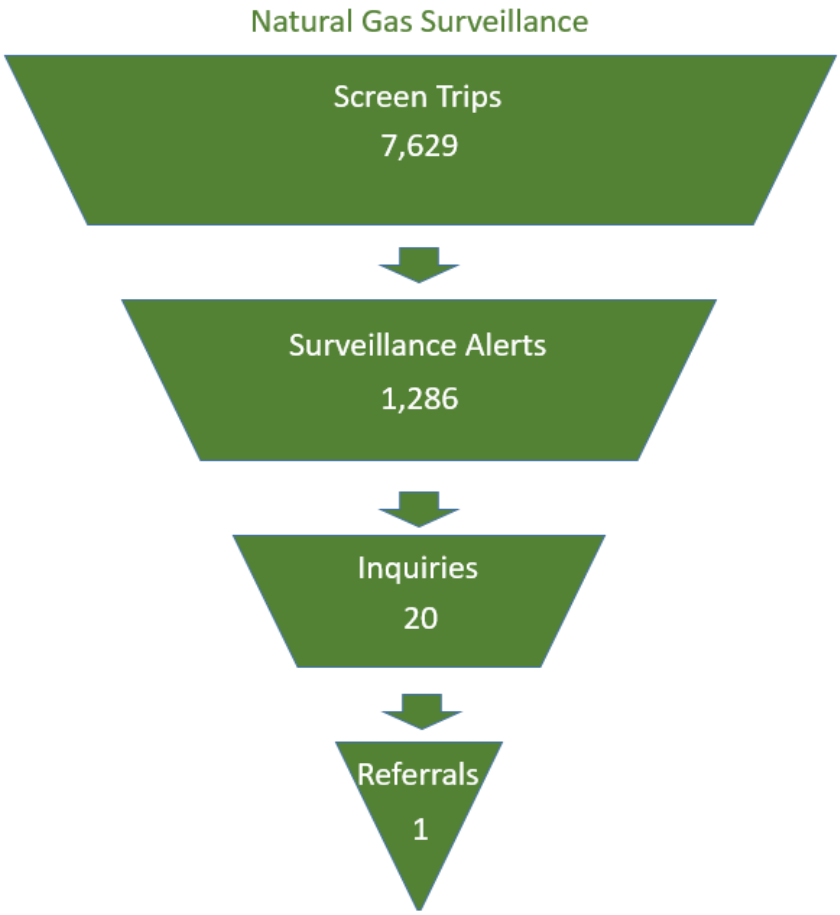
## B. Surveillance

As part of its surveillance function, DAS develops, refines, and implements surveillance tools and algorithmic screens to perform continuous surveillance and analysis of market participant behavior, economic incentives, operations, and price formation, both in the natural gas and electricity markets. In the context of surveillance, DAS seeks to: (1) detect anomalous activities in the markets; and (2) identify potential investigative subjects. When a surveillance screen trips, staff conducts a series of analyses to gain information about the activity that caused it. First, staff evaluates the activity using available market data and information to determine whether there is a fundamentals-based explanation for the activity. Most often, staff finds such an explanation. However, when the follow-up analyses fail to explain the screen trip or surveillance alert, staff performs a more in-depth review of the conduct, which may involve contacting the market participant to request additional information and explanations for the conduct. Staff classifies this enhanced review as the opening of a surveillance inquiry. If, after conducting an inquiry, staff is still concerned that there is a potential violation, it will recommend that DOI open an investigation into the matter.

### 1. Natural Gas

DAS conducts surveillance and analysis of the physical natural gas markets to detect potential manipulation and anti-competitive behavior. Automated natural gas screens cover the majority of physical and financial trading hubs in the United States, monitoring daily and monthly markets. These screens and data feeds alert staff to anomalous market conditions and market participant actions based on a review of supply, demand, pipeline utilization, operational notices, and physical and financial trading. Asset-based screens evaluate natural gas trading around infrastructure, including natural gas storage, pipeline capacity, and electric generation. In addition, DAS uses Large Trader Report data from the CFTC to weigh potential financial incentives that might encourage a market participant to engage in a manipulative scheme.

In FY2019, natural gas surveillance screens produced approximately 7,629 screen trips. Staff reviewed these automated screen trips, compared the conduct that triggered the screen trips to conduct at other hubs, and evaluated whether a fundamentals or physical asset-based explanation existed for the activity. DAS also reviewed other observed anomalous market outcomes for potential concern. In FY2019, staff reviewed and dismissed most of the screen trips as consistent with concurrent conditions. Where concerns remained, staff classified specific screen trips and market activity as "surveillance alerts." Staff documented 1,286 surveillance alerts that ranged in severity from low to high concern. When concerns persisted through more thorough review, DAS opened a surveillance inquiry, which is a more in-depth staff review of the specific trading behavior, which in some cases involves contacting market participants for additional information or to discuss the conduct at issue. In FY2019, DAS conducted 20 such natural gas surveillance inquiries. Of these inquires, DAS referred one to DOI for investigation.

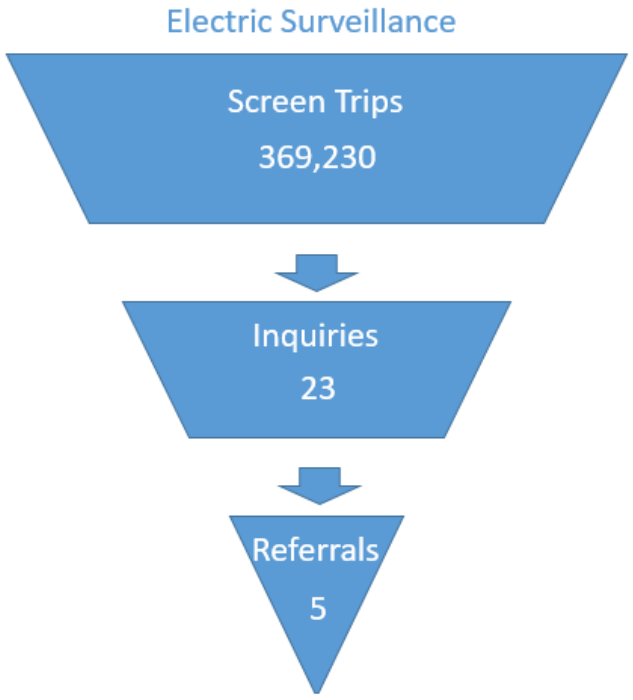



## 2. Electricity

DAS accesses data from a variety of sources to screen for anomalies and potentially manipulative behavior in the ISOs/RTOs and bilateral wholesale electricity markets. During FY2019, staff ran monthly and weekly screens to identify patterns by monitoring the interactions between bids and cleared physical and financially-settled electricity products. In particular, these screens identify financial transmission rights and swap-futures that settle against nodes that are affected by transmission constraints where market participants also trade virtuals, generate electricity, purchase electricity, or move power between Balancing Authorities.

During the fiscal year, staff continued to refine its processes for screening to detect: (1) uneconomic virtual transactions by node, zone, and constraint; (2) day-ahead and real-time market congestion manipulation that would benefit financial transmission rights (FTRs), synthetic real-time FTRs, swap-futures positions for physical load and generation portfolios; (3) anomalies in physical offer patterns, particularly in non-price based parameters; (4) abnormal out-of-market payments; (5) irregularities in capacity market sell offers; and (6) loss making physical fixed-price offer strategies in bilateral electricity markets. DAS also continued to bolster its tools to view patterns of behavior on a portfolio basis, across Balancing Authority borders and jurisdictional commodities.

Each month during FY2019, DAS ran and reviewed 83 electric surveillance screens; monthly, hourly and intra-hour sub-screens; and reports for over 37,000 hub and pricing nodes within the six ISOs/RTOs. Additionally, DAS screened non-RTO markets and cross-RTO portfolio trades for potential manipulation. In reviewing screen trips and, in some cases, after communicating with the ISO/RTO Market Monitoring Units, DAS identified 23 instances of market behavior that required further analysis through a surveillance inquiry. Of the 23 electric surveillance inquiries, five were referred to DOI for investigation, twelve were closed with no referral, and six remain open with staff continuing its analytic work.




## 3. Illustrative DAS Surveillance Inquiries Closed With No Referral

**Market Manipulation (Gas).** DAS natural gas surveillance screens identified a market participant selling at low prices and with high market concentration in bidweek trading at a hub in the West, while holding large short financial basis positions. This created short exposure to next-month bidweek indices like Platts Inside FERC Gas Market Report (IFERC). Staff contacted the market participant, who explained that: (1) the participant needed to sell gas acquired under a long-term contract; (2) limited information concerning current events in the market affected supply and exacerbated the price collapse; and (3) the market experienced low liquidity during the trading period. After staff reviewed additional information provided by the market participant and verified market conditions, DAS closed the surveillance inquiry with no referral to DOI.

**Market Manipulation (Gas).** DAS identified a market participant selling at consecutively lower prices into short financial positions at a western hub during bidweek. At the same time, staff observed that published indices and trade prices diverged. Staff collected index and transaction data to develop a clear picture of the trades' effect on the index price. Staff held a conference call with the market participant, specifically the gas trader, the gas-trading manager, the company's

compliance officer, and outside counsel to discuss the low priced trades. On the call, the company explained its motivation, trading strategy, and build-up of financial positions, as well as the market conditions. In addition, the company sent DAS additional data on pipeline capacity, daily exposure, and over-the-counter (OTC) sales. The company also outlined its internal compliance review process. After staff verified additional information provided by the market participant, DAS closed the matter with no referral to DOI.

**Market Manipulation (Gas/Electric).** DAS evaluated a tip from a Hotline caller that alleged that a market participant imported gas uneconomically and depressed index prices for multiple months to benefit short financial positions. DAS observed that the accused market participant had minimal physical trading activity in the relevant hub, but that it had short financial gas and power positions that stood to benefit from market movements. Upon review, DAS determined that the company's financial gas and power sales could have been a reasonable mechanism to secure fuel for affiliated power generation. DAS closed the inquiry without referral to DOI.

**Market Manipulation (Gas).** DAS reviewed the natural gas trading activities of electric generators that triggered certain key screen trips during specific market events. Staff examined whether this activity might be responsible for some of the high natural gas and related power prices. Staff requested next-day and same-day bids and offers from ICE. The data did not show anomalous order activity, and, therefore, DAS did not refer this matter to DOI.

**Market Manipulation (Gas).** DAS natural gas surveillance screens identified a company that sold gas with high market share, losses, and a large short financial basis position during a bidweek at a northeastern hub. Staff was concerned that the company was depressing prices at this hub in both bidweek and next day markets to benefit its financial short position and to create lower prices for its purchase needs at other hubs in the region. Staff held a conference call with the company and received additional information on the company's interrelated pipeline capacity, risk exposures, and physical transactions. Staff determined that the company had engaged in transportation capacity transactions that had firm deliverability to the hub, and basis spreads along the transport path to an upstream hub justified the pricing of its sales at the hub in question. DAS closed the surveillance inquiry with no referral to DOI.

**Market Manipulation (Electric).** DAS staff routinely reviews cross-market transactions that result in an uneconomic flow of power across ISO/RTO boundaries, because they have the potential to impact prices in a neighboring ISO/RTO. In FY2019, DAS electric surveillance screens flagged more than one market participant exporting power in quantities that were large relative to the interface limit. In these cases, staff ran additional analyses on the market participants' portfolios in both the exporting and importing markets. Staff reviewed potentially benefiting positions such as generation, swaps, and swap futures. DAS closed these inquiries without a referral to DOI, because it did not find a nexus between the loss-making interchange trades and profitable trades elsewhere in the market participants' portfolios.

**Market Manipulation (Electric).** DAS identified a power plant that received large uplift payments during a shoulder month period. One of the plant's units was on outage, and the other units were needed for reliability. In addition, the start-up costs submitted for the plant during this shoulder month period were higher than normal. Further research revealed that the plant had a temporary adder in place. The market participant provided information on the additional costs

that demonstrated that they related to the ongoing operation of the remaining units. DAS closed this inquiry with no referral to DOI.

**Market Manipulation (Electric).** DAS electric surveillance screens identified a market participant that repeatedly sold physical power at a Western bilateral trading hub, while appearing to hold a corresponding leveraged short financial position at the same hub that would benefit from a lower index. The market participant had high concentration levels and often transacted at the beginning of trade sessions when the bid-ask spread was the highest. Staff conducted an inquiry into the market participant's portfolio and determined that the market participant was using hub transactions to market output from a plant it owned to the broader region, and that the physical power sales were economic. Staff further determined that, after accounting for all the market participant's physical and financial exposure to the hub, the financial position was not leveraged. As a result, the inquiry was closed without a referral to DOI.

**Market Manipulation (Electric).** DAS routinely focuses on virtual trading. Several surveillance screens identify virtual bidding behavior that appears uneconomic or otherwise anomalous. In the past year, several market participants were flagged for further analysis. In one such case, a market participant consistently traded Decrement Bids (DECs) into a large, leveraged long swap-futures position. Deeper analysis revealed that the trader had an over-the-counter short position that was being hedged with the swap-futures. As a result, the inquiry was closed with no referral to DOI.

**Market Manipulation (Electric).** DAS electric surveillance screens identified a market participant whose virtual positions appeared to be creating or aggravating a binding constraint in the day-ahead market. Staff analyzed the trader's effective positions potentially affecting the constraint, and its effective downstream positions that could benefit. Staff concluded that the virtual positions were too small and inconsistent throughout the month to cause the constraint to bind. As a result, the inquiry was closed with no referral to DOI.

## C. Analytics

During FY2019, DAS worked on approximately 45 investigations, some of which are discussed above in the DOI section. Many of these investigations involve allegations of manipulation in the Commission-jurisdictional natural gas and electricity markets, or violations of tariff provisions that are intended to foster open, competitive markets. DAS' investigative activities generally include: (1) assessing market conditions during periods of suspected manipulation; (2) identifying patterns of market activity that could indicate market manipulation; (3) identifying time periods in which potentially manipulative activities occurred; (4) fully reconstructing and analyzing companies' trading portfolios; (5) supporting DOI in taking investigative testimony; and (6) calculating the amount of unjust profits and market harm resulting from violations to assist with determining a civil penalty recommendation under the Commission's penalty guidelines. Upon completion of the analytical process, staff develops data-based explanations to inform the structure and substance of further investigation, settlement discussions, and Commission actions. Staff also coordinates internally to refine and develop new screens to detect improper behavior discovered in prior investigations.

## D. Data Management

During FY2019, DAS staff worked to streamline its Order No. 760 data collection efforts and to improve data usability within DAS and throughout the Commission. On streamlining its Order No. 760 collection, DAS' efforts included: (1) deploying a centralized platform with each ISO/RTO to track their system changes and to track issues; and (2) working with FERC's Office of the Chief Information Officer to more quickly deploy ISO/RTO data model changes into FERC's Order No. 760 databases.

On the data usability front, DAS' efforts in FY2019 included: (1) researching best-in-class data management organizational structures in government; (2) designing, building, and maintaining managed data pipelines; and (3) collaborating across offices to improve master data management. In addition, DAS, in collaboration with FERC IT, deployed the first cloud environment with secure production data at the Commission. Using this environment, the team delivered five proof-of-concepts, including new data visualization interfaces for important electric market data. Finally, the team designed, recommended, and supported the creation of the new Data Governance Division in the Office of the Executive Director. This Division, led by the Commission's first Chief Data Officer, will pursue best-in-class data strategy, management, and analytics. These data management efforts are consistent with Objective 3.1 of the Commission's FY2018-2022 Strategic Plan.[59]

[59] *See* Strategic Plan, *supra* note 4, at 21-25 (Objective 3.1).

# DIVISION OF ENERGY MARKET OVERSIGHT

## A. Overview

In support of the Commission's responsibility to ensure just and reasonable rates, terms, and conditions for consumers, the Division of Energy Market Oversight (DEMO) was responsible for monitoring and analyzing the nation's wholesale natural gas and electric power markets. DEMO performed this monitoring and analysis by: (1) examining and analyzing the structure and operation of the markets to identify significant market events and trends, inefficient market rules, tariff and rule violations, and other unusual market behavior; (2) analyzing market-based rate transactions to determine whether entities are exercising market power, and reporting its various analyses and observations to the Commission; (3) collaborating with other Commission offices to develop regulatory strategies, focusing on the competitiveness, fairness, and efficiency of wholesale energy markets; (4) administering, analyzing, and ensuring compliance with the filing requirements of Electric Quarterly Reports (EQRs) and various Commission forms; and (5) conducting outreach to and communication with the public. As described above, pursuant to a September 2019 realignment, DEMO's functions were realigned to better reflect the key functions and mission statements of Commission offices. The functions described in this section continue to be carried out by staff in OEPI, DAA, and DAS.

## B. Market Monitoring

DEMO staff examined data from a variety of sources to review market fundamentals and emerging trends, and to examine the structure, operation, and interaction of natural gas and electric markets. As developments warranted, DEMO staff initiated projects designed to evaluate market trends and assess participant behavior. Staff also presented analyses at Commission meetings and made analyses available to the public on the Commission website. During FY2019, such reports and presentations included the following:

### 1. 2018 State of the Markets Report

DEMO presented to the Commission, and made public, its State of the Markets report, which assessed the significant events in the energy markets during the prior year.[60] Posted on April 18, 2019, the report for 2018 reviewed trends and events in natural gas and power markets, including trends in prices, supply, and demand. The report also reviewed the development of US pipeline infrastructure and the rapid increase in the LNG export industry.

[60] *See* State of the Markets Report 2018, *available at* http://www.ferc.gov/market-assessments/reports-analyses/st-mkt-ovr/2018-A-3-report.pdf.

### 2. Seasonal Market Assessments

DEMO prepared seasonal assessments that it presented at Commission meetings and made available to the public on the Commission website. In FY2019, DEMO's seasonal assessments included the following:

**Winter 2018-2019 Energy Market Assessment, October 18, 2018.** DEMO staff presented its assessment of fuel and electricity market preparedness for the 2018-19 winter season. For fuels markets, the assessment covered natural gas storage volumes, regional natural gas price outlooks, and pipeline capacity expansion. For electricity markets, the assessment examined gas-oil switching in the Eastern U.S., including the use of dual-fuel generators to hedge fuel price volatility, as well as the adequacy of regional electric power supplies and trends in capacity additions and retirements. The assessment also discussed gas pipeline restrictions in Southern California and ISO New England's Pay-for-Performance capacity construct.[61]

**Summer 2019 Energy Market and Reliability Assessment, May 16, 2019.** This assessment reviewed the outlook for the electricity and fuels markets for summer 2019. For electricity markets, the assessment discussed the adequacy and diversity of regional electric power supplies, CAISO's hydroelectric generation outlook, and trends in renewable generation and battery storage. For fuels markets, the assessment presented an analysis of regional natural gas futures prices, as well as the growth in LNG exports. The presentation also discussed expectations for natural gas storage volumes.[62]

As of the September 2019 realignment, these reports will continue to be drafted and presented by staff now assigned to OEPI.

## C. Market-Based Rate *Ex Post* Analysis

DEMO developed, refined, and implemented tools and algorithmic indicators to conduct ongoing analysis of transactional and other market data to detect the presence of market power, and to ensure that jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential. This *ex post* analysis evaluated transactions against market fundamentals at the time of execution, with the primary goal of identifying outcomes that may be inconsistent with expectations of a competitive market, and thus an indication of an exercise of market power. Once such outcomes were identified, DEMO coordinated with other Commission program offices to determine whether to recommend the Commission take action to remedy market power concerns. DEMO also used these tools to assist in analyzing applications and filings for market-based rates, public utility mergers, and other docketed proceedings. Since the September 2019 realignment, this function has been and will continue to be performed by staff now assigned to DAS.

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[61] *See* Winter 2018-2019 Energy Market Assessment, *available at* http://www.ferc.gov/market-assessments/reports-analyses/mkt-views/2018/10-18-18-A-3.pdf.

[62] *See* Summer 2019 Reliability and Energy Market Assessment, *available at* http://www.ferc.gov/market-assessments/reports-analyses/mkt-views/2019/05-16-19.pdf.

## D. Commission Orders and Rulemakings

DEMO assisted the Commission in evaluating the efficacy of certain regulatory policies in light of evolving energy markets and ensured that the Commission has the information needed to administer and monitor the markets effectively. In FY2019, DEMO assisted with over 40 docketed Commission proceedings. Through its work on these matters, DEMO sought to enhance market transparency and efficiency while balancing the regulatory burden on market participants. Since the September 2019 realignment, this function has been and will continue to be performed by staff now assigned to DAS and OEPI.

## E. Forms Administration and Compliance

DEMO staff administered and ensured compliance with certain Commission filing requirements. The Commission requires companies subject to its jurisdiction to submit financial statements, operational data, and annual and quarterly reports regarding jurisdictional sales. It uses these reports for various analyses, such as evaluations of whether existing rates continue to be just and reasonable. Other government agencies and industry participants also use them for a variety of business purposes.

### 1. Electric Quarterly Reports

Section 205 of the FPA, 16 U.S.C. § 824d (2012), and Part 35 of the Commission's regulations, 18 C.F.R. Part 35 (2019), require, among other things, that all rates, terms, and conditions of jurisdictional service be filed with the Commission. In Order No. 2001, the Commission revised its public utility filing requirements to require public utilities, including power marketers, to file EQRs summarizing the contractual terms and conditions in their agreements for all jurisdictional services (including market-based power sales, cost-based power sales, and transmission service) and providing transaction information (including rates) for short-term and long-term power sales during the most recent calendar quarter.[63]

In FY2019, the Commission received EQR submittals from nearly 2,600 entities each quarter. DEMO assessed whether sellers timely complied with the requirements set forth in the multiple orders surrounding EQR filings, and, through automated validations, whether the data was accurate and reliable. It also coordinated with DAA on EQR issues that arose during audits and submitted candidate entities that did not timely file their EQRs to OEMR for possible revocation of Market-Based Rate authority. DEMO held one EQR user group meeting in FY2019 to conduct outreach

[63] *Revised Public Utility Filing Requirements,* Order No. 2001, FERC Stats. & Regs. ¶ 31,127 (2002), *reh'g denied*, Order No. 2001-A, 100 FERC ¶ 61,074 (2002), *reh'g denied,* Order No. 2001-B, 100 FERC ¶ 61,342 (2002), *order directing filing,* Order No. 2001-C, 101 FERC ¶ 61,314 (2002), *order directing filing,* Order No. 2001-D, 102 FERC ¶ 61,334 (2003), *order refining filing requirements*, Order No. 2001-E, 105 FERC ¶ 61,352 (2003), *order on clarification*, Order No. 2001-F, 106 FERC ¶ 61,060 (2004), *order revising filing requirements*, Order No. 2001-G, 120 FERC ¶ 61,270 (2007), *order on reh'g and clarification*, Order No. 2001-H, 121 FERC ¶ 61,289 (2007), *order revising filing requirements*, Order No. 2001-I, FERC Stats. & Regs. ¶ 31,282 (2008).

with the filing community and to discuss potential system improvements and enhancements. More than 370 participants attended this meeting either in person or via webcast/phone. Staff also updated the EQR Frequently Asked Questions (FAQs)[64] and the provided additional assistance to filers.

Since the September 2019 realignment, this function has been and will continue to be performed by staff now assigned to DAA.

### 2. eForms Refresh Project

On April 16, 2015, the Commission directed Commission staff to begin the process of replacing its electronic filing format for many of the forms submitted by the industry, as the current filing software is no longer supported.[65] On June 20, 2019, the Commission issued a final rule adopting eXtensible Business Reporting Language (XBRL) as the standard for filing these forms.[66] Throughout FY2019, DEMO staff, with the assistance of subject matter and technical experts from other Commission program offices, worked on the process for selecting a contractor to develop the XBRL standard and on resolving issues associated with transitioning from the current filing software to the XBRL standard.

Since the September 2019 realignment, this function has been and will continue to be performed by staff now assigned to DAA.

## F. Outreach and Communication

DEMO made some of its analyses available to the public by posting reports on its website and hosting periodic snapshot presentations. Staff also briefed visiting industry participants, state and federal officials, and foreign delegations.

### 1. Website

DEMO published data and analyses on the FERC website, which was organized into pages for: (1) national overviews of natural gas and electricity markets; and (2) ten regional electricity and five regional natural gas markets.[67] The regional market pages provided charts, tables, and maps displaying market characteristics and outcomes.

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[64] *See* EQR Frequently Asked Questions, *available at* http://www.ferc.gov/resources/faqs/eqr-2013.asp.

[65] *Order Instituting Proceeding to Develop Electronic Filing Protocols for Commission Forms*, 151 FERC ¶ 61,025 (2015).

[66] *Revisions to the Filing Process for Commission Forms*, Order No. 859, 167 FERC ¶ 61,241 (2019).

[67] This information is available at https://www.ferc.gov/market-assessments/market-assessments.asp.

## 2. Snapshot Calls

DEMO held semi-annual conference calls with representatives of public utility commissions and state agencies in the eastern, central, and western states. These calls provided a current "snapshot" of energy markets. Regional Snapshot Reports, which included data and information on natural gas, electricity, LNG, weather, infrastructure development, and other market developments, served as the basis for discussion on the calls. DEMO's Snapshot Reports are available on the FERC website and are archived back to 2007.[68]

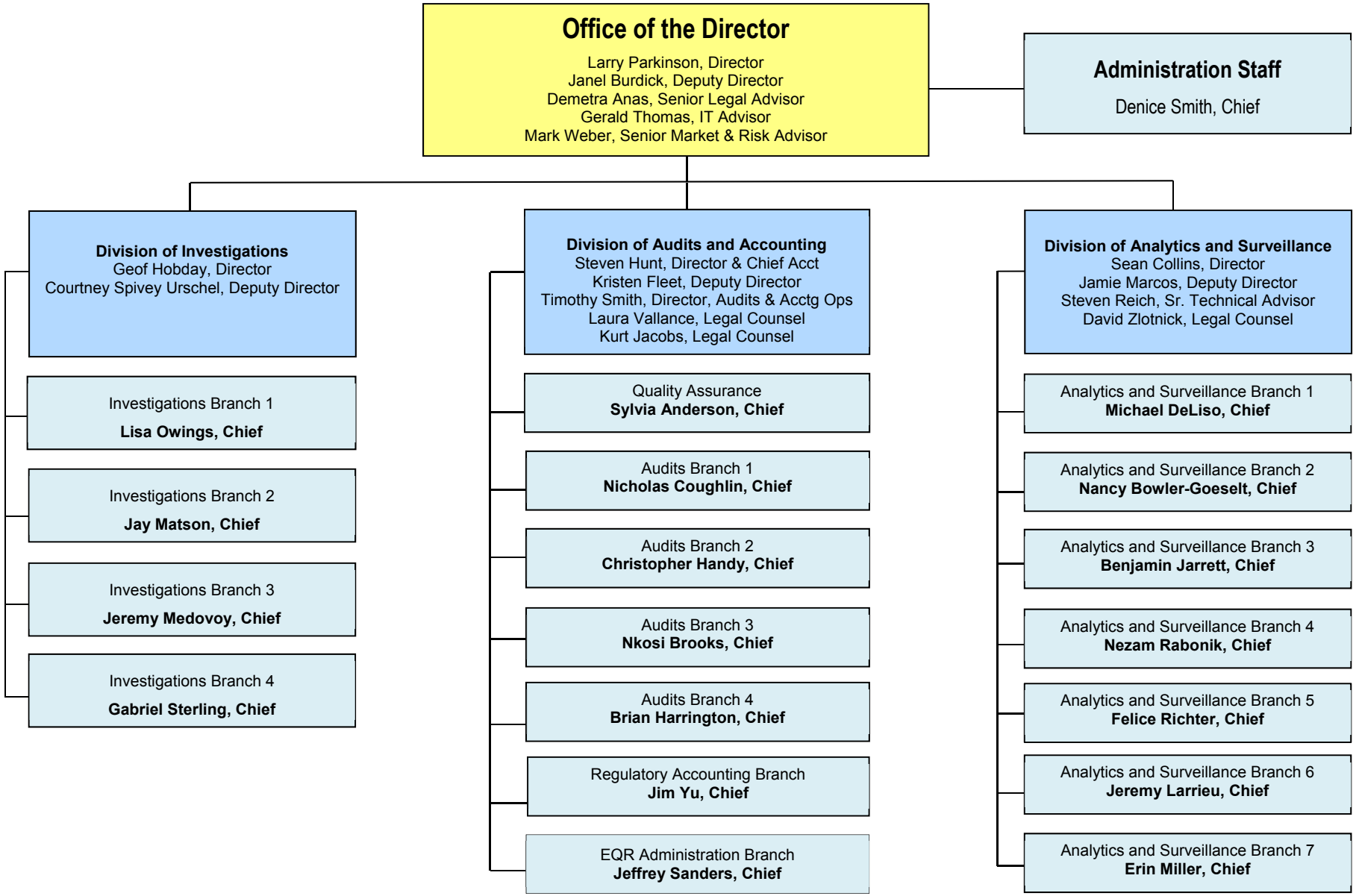
## 3. Domestic and Foreign Delegation Briefings

DEMO periodically hosted visitors, including domestic and foreign delegations of regulators and industry participants, who were interested in energy markets and in the Commission's market monitoring activities. In FY2019, DEMO conducted 12 briefings for various domestic and foreign delegations in the Market Monitoring Center.

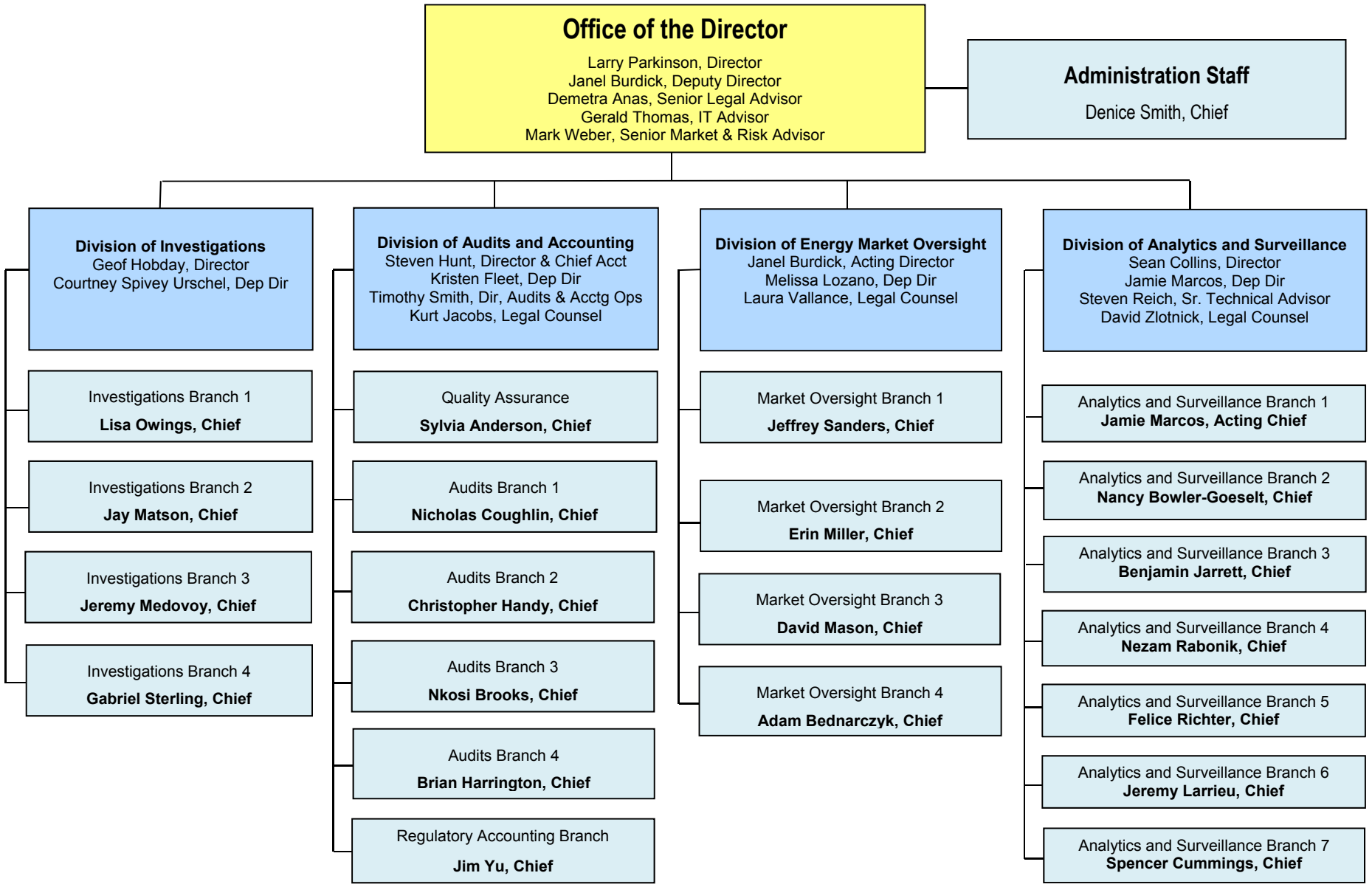
Since the September 2019 realignment, these outreach functions have been and will continue to be performed by staff now assigned to DAS and OEPI.

[68] DEMO's Snapshot Reports are available at https://www.ferc.gov/market-assessments/mkt-snp-sht/mkt-snp-sht.asp.

# APPENDIX A1: OFFICE OF ENFORCEMENT ORGANIZATION CHART (CURRENT)



# APPENDIX A2: OFFICE OF ENFORCEMENT ORGANIZATION CHART (THRU 9/15/19)



# APPENDIX B: FY2019 CIVIL PENALTY ENFORCEMENT ACTIONS[69]

| Subject of Investigation and Order Date | Total Payment | Explanation of Violations |
|---|---|---|
| Algonquin Gas Transmission, LLC, Docket No. IN19-2-000, Order Approving Stipulation and Consent Agreement, 166 FERC ¶ 61,012. | $400,000 civil penalty. | The Commission approved a Stipulation and Consent Agreement between Enforcement and Algonquin Gas Transmission, LLC (Algonquin), resolving Enforcement's investigation into whether Algonquin violated the express terms of the Commission-issued Algonquin Incremental Market (AIM) Project Certificate, granted under section 7(c) of the NGA, when it entered a wetland area outside the AIM Project's right of way with construction equipment in an attempt to retrieve a broken drill stem without obtaining a variance from the Commission as required. |
| Virginia Electric & Power Company, d/b/a Dominion Energy Virginia, Docket No. IN19-3-000, Order Approving Stipulation and Consent Agreement, 167 FERC ¶ 61,103. | $7 million civil penalty; $7 million disgorgement. | The Commission approved a Stipulation and Consent Agreement between Enforcement and Virginia Electric & Power Company, d/b/a Dominion Energy Virginia (DEV), resolving Enforcement's investigation into whether DEV violated Commission regulations, including the Anti-Manipulation Rule, 18 C.F.R. § 1c.2 (2018), by improperly targeting and increasing its receipt of lost opportunity cost credits (LOCs) in the PJM Interconnection, L.L.C. (PJM) market. |

[69] A list of all post-EPAct 2005 civil penalty orders is available at http://www.ferc.gov/enforcement/civil-penalties/civil-penalty-action.asp.

Docket No. UE 433
Exhibit PAC/3304
Witness: Sherona L. Cheung

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Sherona L. Cheung**

**2017 FERC Audit of PacifiCorp's Compliance**

**July 2024**

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. FA16-4-000
August 29, 2017

Sarah E. Edmonds
PacifiCorp
Vice President and General Counsel
825 NE Multnomah Street, Suite 1800
Portland, OR 97232

Dear Ms. Edmonds:

1. The Division of Audits and Accounting within the Office of Enforcement of the Federal Energy Regulatory Commission (Commission) has completed an audit of PacifiCorp (Company). The audit covered the period of January 1, 2013 to December 31, 2015.

2. The audit evaluated PacifiCorp's compliance with (1) approved terms, rates, and conditions of its wholesale formula rate mechanism as outlined in PacifiCorp's Open Access Transmission Tariff (OATT), and other jurisdictional rates on file with the Commission, (2) the accounting requirements of the Uniform System of Accounts Prescribed for Public Utilities and Licensees under 18 C.F.R. Part 101, and (3) the reporting requirements of the FERC Form No. 1, Annual Report, under 18 C.F.R. § 141.1. The enclosed audit report contains nine findings and 38 recommendations that require PacifiCorp to take corrective action.

3. On August 22, 2017, you notified DAA that PacifiCorp accepts the audit report. A copy of your verbatim response is included as an appendix to this report. I hereby approve the audit report.

4. PacifiCorp should submit its implementation plan to comply with the recommendations within 30 days of this letter order. PacifiCorp should make quarterly submissions to DAA describing the progress made to comply with the recommendations, including the completion date for each corrective action. As directed by the audit report, these submissions should be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after this audit report is issued, and continuing until all the corrective actions are completed.

5. The Commission delegated authority to act on this matter to the Director of OE under 18 C.F.R. § 375.311 (2017). This letter order constitutes final agency action.

6. This letter order is without prejudice to the Commission's right to require hereafter any adjustments it may consider proper from additional information that may come to its attention. In addition, any instance of noncompliance not addressed herein or that may occur in the future may also be subject to investigation and appropriate remedies.

7. I appreciate the courtesies extended to the auditors. If you have any questions, please contact Mr. Bryan K. Craig, Director and Chief Accountant, Division of Audits and Accounting at (202) 502-8741.

Sincerely,

Larry R. Parkinson
Director
Office of Enforcement

Enclosure

**Federal Energy Regulatory Commission**
Office of Enforcement
Division of Audits and Accounting

# AUDIT REPORT

# Audit of PacifiCorp's compliance with its wholesale formula rate; the accounting requirements of the Uniform System of Accounts Prescribed for Public Utilities and Licensees; and the reporting requirements of the FERC Form No. 1, Annual Report.

Docket No. FA16-4-000
August 29, 2017

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# I. Executive Summary

## A. Overview

The Division of Audits and Accounting (DAA) in the Office of Enforcement of the Federal Energy Regulatory Commission (Commission) has completed an audit of PacifiCorp (Company). The audit evaluated PacifiCorp's compliance with requirements of PacifiCorp's Open Access Transmission Tariff (OATT). Specifically, the audit evaluated whether PacifiCorp complied with: (1) protocols and instructions for the various accounts incorporated in its wholesale formula rate; (2) the accounting requirements of the Uniform System of Accounts (USofA) Prescribed for Public Utilities and Licensees under 18 C.F.R. Part 101; and (3) FERC Form No. 1 reporting requirements for Major Electric Utilities under 18 C.F.R. § 141.1. The audit covered the period January 1, 2013 to December 31, 2015.

## B. PacifiCorp

PacifiCorp was established in 1910 under the name Pacific Power & Light Company. In 1984, Pacific Power & Light Company changed its name to PacifiCorp. In 1989, PacifiCorp formed the entity operating today by merging with Utah Power and Light Company to form an Oregon corporation. PacifiCorp is a vertically integrated electric utility company providing utility services to over 1.8 million customers in six states: Utah, Wyoming, Idaho, Oregon, Washington, and California. PacifiCorp provides electric service to customers in Utah, Wyoming and Idaho under the trade name Rocky Mountain Power and to customers in Oregon, Washington, and California under the trade name Pacific Power. PacifiCorp also operates a business unit called PacifiCorp Transmission, which includes transmission operations, and related Energy Gateway Expansion projects for the company. PacifiCorp is principally engaged in the business of generating, transmitting, distributing, and buying and selling electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants.

PacifiCorp is a wholly owned subsidiary of Berkshire Hathaway Energy Company (BHE), through an intermediate parent, PPW Holdings LLC. PacifiCorp owns, or has interests in, 75 thermal, hydro-electric, wind-powered, coal, and geothermal generating facilities, with a net owned capacity of 10,894 MW. The company has interests in four coal mining operations to support power generation at its coal generating facilities. PacifiCorp also owns, or has interests in, electric transmission and distribution assets and transmits electricity through approximately 16,500 miles of transmission and 64,000 miles of distribution lines.

## C. Summary of Audit Findings

Audit staff's compliance findings are summarized below. Details of these findings are in Section IV of this report. Audit staff found nine areas of noncompliance.

- *Storm Damage Accounting and Costs Recovery* - PacifiCorp's accounting and wholesale formula rate billings for storm damage costs during the period of 2012 through 2015 were deficient as follows:

    - PacifiCorp improperly overbilled storm damage costs to its merchant function and third-party wholesale customers that procured transmission services under PacifiCorp's OATT. This occurred because PacifiCorp improperly included actual plus estimated costs associated with the same storms in billings to its merchant and third-party wholesale customers. As a result, PacifiCorp overstated its wholesale transmission revenue requirement by approximately $6.9 million, which led to overbillings to third-party wholesale customers by approximately $1.1 million.

    - PacifiCorp did not make refunds to its wholesale customers for the excessive storm damage revenues collected from its wholesale customers.

- *Mining Assets* - PacifiCorp inappropriately recovered from its wholesale customers the cost of production related mining assets through its wholesale formula rates. As a result, PacifiCorp overstated its wholesale transmission revenue requirement by approximately $3.7 million, which led to overbillings to third-party wholesale customers by approximately $600,000.

- *Amortization of Regulatory Assets* - PacifiCorp inappropriately included amortization of regulatory assets in its wholesale formula rates. As a result, PacifiCorp overstated its wholesale transmission revenue requirement by approximately $800,000, which led to overbillings to third-party wholesale customers of approximately $100,000.

- *Injuries and Damages Accounting and Costs Recovery* - PacifiCorp improperly classified injuries and damages accruals and recovered those costs through its wholesale formula rates when it had insurance policies to cover the cost of those damages. As a result, PacifiCorp overstated its wholesale transmission revenue requirement by approximately $2.9 million, which led to overbillings to third-party wholesale customers by approximately $400,000.

- *Allowance for Funds Used During Construction* - PacifiCorp's methods for calculating Allowance for Funds Used During Construction (AFUDC) rate was deficient as follows:

    - PacifiCorp inappropriately included letter of credit fees (up-front and quarterly) as part of short term debt interest expense to compute AFUDC rate.

    - PacifiCorp inappropriately included Unappropriated Undistributed Subsidiary Earnings as part of the equity component for the purpose of computing AFUDC rate.

    - PacifiCorp inappropriately included Accumulated Other Comprehensive Income (AOCI) as part of the equity component for the purpose of computing AFUDC rate in 2013.

  As a result, PacifiCorp over accrued Allowance for Funds Used During Construction by approximately $6.8 million for 2013 through 2015. PacifiCorp overbilled wholesale customers for the excessive AFUDC costs included in utility plant that was included in wholesale formula rates determinations through rate base and depreciation charges.

- *Asset Retirement Obligations* - PacifiCorp's accounting and rate treatment of Asset Retirement Obligations (ARO) were deficient as follows:

    - PacifiCorp inappropriately excluded accumulated depreciation amounts removed from Account 108, Accumulated Provision for Depreciation of Electric Utility Plant, to implement ARO accounting in the wholesale formula rates determinations. As a result, PacifiCorp understated its wholesale transmission revenue requirement which led to under-billings to its wholesale customers through its wholesale formula rates.

    - PacifiCorp inappropriately included estimated future asset retirement costs recorded in General Plant in its wholesale formula rate base. As a result, PacifiCorp overstated its wholesale transmission revenue requirement, which led to overbillings to its wholesale customers.

  As a result of the deficiencies, PacifiCorp under-billed its wholesale customers through its wholesale formula rates.

- *Accounting for Coal Settlement Costs* - PacifiCorp incorrectly accounted for amortization of two coal settlement payments in Account 151, Fuel Stock, instead of Account 501, Fuel.

- *Accounting for Liquidated Damages* - PacifiCorp incorrectly accounted for amortization of production related regulatory assets associated with liquidated damages as an administrative and general expense in Account 930.2, Miscellaneous General Expense.

- *Accounting for Pensions, PBOP and Other Benefits* - PacifiCorp recorded the cost of pensions, post-retirement benefits other than pensions (PBOP) and other employee benefits in various functional operating and maintenance expense accounts, instead of in Account 926, Employee Pensions and Benefits.

## D. Summary of Recommendations

This section summarizes audit staff's recommendations to remedy this report's findings. Audit staff's 38 compliance recommendations are summarized below and detailed in Section IV. To address the areas of noncompliance, audit staff recommends that PacifiCorp:

*Storm Damage Accounting and Costs Recovery*

1. Refrain from recovering actual and estimated storm damage costs from wholesale customers associated with the same storm. Revise policies, procedures and practices to ensure the proper accounting procedures are employed to prevent the double collection of storm damage costs through the wholesale formula rates.

2. Revise wholesale formula rates development procedures to strengthen coordination between accounting and wholesale formula rates development departments.

3. Provide training to staff on the revised storm damage accounting and rate development methods. Also, develop a training program that supports the provision of periodic training in this area, as needed.

4. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate storm damage recoveries since 2012, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to be refunded; and (5) period(s) refunds will be made. Include the results of the analysis of transmission-related storm damage expenses in the refund amount.

5. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

6. Refund amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of Commission regulations.

*Mining Assets*

7. Revise procedures for computing the annual wholesale transmission revenue requirement and billing to wholesale customers by ensuring that it excludes cost of mining assets from the wholesale formula rates.

8. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate cost of mining asset recoveries that resulted from the inclusion of mining assets in the wholesale formula rates base since 2012, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to be refunded and (5) period(s) refunds will be made.

9. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

10. Refund amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of Commission regulations.

*Amortization of Regulatory Assets*

11. Revise accounting procedures to record pensions, and postretirement regulatory asset amortizations in Account 926.

12. Revise accounting procedures to exclude amortization of environmental damages regulatory assets to Account 925, and record amortization of amounts recovered in retail rates in appropriate functional operating and maintenance accounts.

13. Provide training to staff on the revised regulatory assets accounting and rate development methods. Also, develop a training program that supports the provision of periodic training in this area, as needed.

14. Record correcting entries to reclassify pensions, and postretirement regulatory assets amortization from Account 920 to Account 926.

15. Record correcting entries to reclassify environmental damages amortization from Account 925 and record the amounts recovered from retail rates in appropriate functional operating and maintenance accounts.

16. Revise procedures for computing wholesale formula rates billings to wholesale customers to exclude amortization of regulatory assets which were not approved by the Commission.

17. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate regulatory asset amortizations which were included in wholesale formula rates and the refunds resulting from the inclusion of those regulatory asset amortizations in the wholesale formula rates, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to be refunded and (5) period(s) refunds will be made.

18. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

19. Refund amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of Commission regulations.

*Injuries and Damages Accounting and Costs Recovery*

20. Revise policies, procedures and practices to book accruals for covered damage amounts in Account 426.5 when management makes a decision not to seek insurance recoveries for damages covered by insurance.

21. Provide training to staff on the revised injuries and damages expenses covered by insurance accounting and rate development methods. Also, develop a training program that supports the provision of periodic training in this area, as needed.

22. Submit a refund analysis within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate injuries and damages recoveries that resulted from the inclusion of excessive estimated expenses in the wholesale formula rates since 2012, plus interest; (2) determinative

components of the refund; (3) refund method; (4) customers to be refunded; and (5) period(s) refunds will be made.

23. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

24. Refund amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of Commission regulations.

*Allowance for Funds Used During Construction*

25. Revise its procedures to ensure its AFUDC rate calculation is consistent with Order No. 561 and other applicable Commission requirements.

26. Revise its procedures to ensure that Account 216.1 is excluded from equity components used to derive AFUDC rate.

27. Revise its procedures to ensure that the amounts reported on the FERC Form No. 1 are used to compute AFUDC rate.

28. Provide training to staff on the revised AFUDC accounting and rate calculation method. Also, develop a training program that supports the provision of periodic training in this area, as needed.

29. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds to wholesale customers base since 2012, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to be refunded and (5) period(s) refunds will be made.

30. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

31. Refund amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of Commission regulations.

*Asset Retirement Obligations*

32. Revise existing accounting and rate development procedures and practices to ensure all ARO-related accounting effects and associated adjustments are excluded from wholesale formula rates determinations.

*Accounting for Coal Settlement Costs*

33. Establish procedures to identify components of coal settlement cost between past coal supply disputes and costs that provide future benefits.

34. Establish procedures to expense immediately prior disputed costs that is related to coal already consumed in Account 501, unless rate recognition is approved by a regulatory authority.

35. Revise accounting procedures to record amortization of deferred coal settlement and renegotiation costs in Account 501.

*Accounting for Liquidated Damages*

36. Revise accounting procedures to record regulatory asset amortization related to production plant liquidated damages in the functional operating and maintenance accounts when appropriate.

37. Record correcting entries to reclassify regulatory asset amortization related to state created advance refund of liquidated damages from Account 930.2 to Account 557, Other Expenses.

*Accounting for Pensions, PBOP and Other Benefits*

38. Revise procedures to ensure it records pensions, PBOP, and other employee benefits in Account 926, Employee Pensions and Benefits, as required by the Commission accounting regulations.

## E. Compliance and Implementation of Recommendations

Audit staff further recommends that PacifiCorp submit the following for audit staff's review:

- A plan for implementing the audit recommendations within 30 days after the final audit report is issued in this docket;

- Quarterly reports describing progress in completing each corrective action recommended in the final audit report. Quarterly, nonpublic submissions should be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after the final audit report is issued, and continuing until all recommended corrective actions are completed; and

- Copies of any written policies and procedures developed in response to recommendations in the audit report. These documents should be submitted in the first quarterly filing after PacifiCorp completes the products.

# II. Background

## A. PacifiCorp's Transmission System

PacifiCorp used its electric transmission system, which was connected throughout its six operating states, for transmission of electricity of others as well as to serve PacifiCorp's native load. PacifiCorp's own use of the transmission system was to provide transmission of electricity for sale by PacifiCorp for resale by other utilities and public authorities, and to serve PacifiCorp's customers under retail jurisdictions. PacifiCorp's transmission customers executed service agreements stipulating the terms and conditions, and applicable tariffs for PacifiCorp's transmission service. The service agreements were entered into between PacifiCorp Transmission and all transmission customers, including PacifiCorp – Merchant Function which represented PacifiCorp's own use of the transmission system. PacifiCorp's cost to operate the transmission system was billed to wholesale customers through wholesale formula rates, described below, for the transmission of electricity of others. PacifiCorp's share of the cost of transmission system for its own use was billed to its merchant function. In limited situations, PacifiCorp's wholesale customers were directly billed for transmission based on wholesale formula rates.

## B. Wholesale Formula Rate

PacifiCorp's OATT includes a wholesale formula rate which is used to derive a system-wide transmission service rate. PacifiCorp filed its transmission rate case with the Commission in Docket No. ER11-3643-000 in 2011. The revisions to PacifiCorp's OATT in the docket included an amendment of Attachment H (Annual Transmission Revenue Requirement for Network Integration Transmission Service), and the addition of Attachment H-1 (PacifiCorp's Formula Rate) and Attachment H-2 (i.e., the Protocols) to comprise PacifiCorp's wholesale formula rate inputs. PacifiCorp's charges for Point-to-Point Transmission Service (PTP Service) and Network Integration Transmission Service (NIT Service) under PacifiCorp's OATT are calculated annually using the Annual Transmission Revenue Requirement (ATRR), which is derived from the formula defined in the OATT. The ATRR determined for a rate year is billed to PacifiCorp's own use of the transmission system to serve PacifiCorp's distribution and wholesale customers, and to provide transmission of electricity of others.[1]

[1] PacifiCorp developed projected rates annually, effective from June 1 to May 31. Actual rates were developed on a calendar year basis. Long term firm point-to-point and network integration transmission service customers who were billed projected rates were trued-up for the actual rates.

The wholesale formula rate is the product of a settlement agreement negotiated by PacifiCorp with it transmission customers, and was approved by the Commission and added to the OATT in 2013, with a retroactive effective date of December 25, 2011. Since its approval of the settlement agreement in 2013, the Commission has approved various revisions and updates to Attachment H and other attachments to the formula to incorporate additional settlements with transmission customers (e.g., updates to the depreciation rate[2] and using actual post-retirement benefits other than pensions (PBOP) expense instead of fixed PBOP expense).[3]

[2] *See* Docket Nos. ER13-1207, ER14-918, ER14-1601, ER14- 01635.
[3] *PacifiCorp*, 149 FERC ¶ 61,267 (2014).

# III. Introduction

## A. Objectives

The DAA conducted an audit of PacifiCorp, evaluating PacifiCorp's compliance with: (1) approved terms, rates, and conditions of its wholesale formula rate mechanism as outlined in the PacifiCorp's OATT, and other jurisdictional rates on file with the Commission, (2) the accounting requirements of the Uniform System of Accounts Prescribed for Public Utilities and Licensees under 18 C.F.R. Part 101, and (3) the reporting requirements of the FERC Form No. 1, Annual Report, under 18 C.F.R. § 141.1. The audit covered January 1, 2013 to December 31, 2015. Additional limited audits, in light of certain audit findings, covered years prior to 2013 and the year 2016.

## B. Scope and Methodology

To evaluate PacifiCorp's compliance with the terms and conditions of its OATT, audit staff performed these procedures:

- *Review of Public Information* – Before commencing the audit on March 7, 2016, reviewed publicly available materials to obtain a broad understanding of PacifiCorp's corporate structure, regulatory actions and history, system infrastructure and operations, tariff procedures and services, wholesale energy transactions, wholesale formula rate protocols and calculation, and other pertinent business and regulatory aspects. Also, reviewed information included PacifiCorp's FERC Form Nos. 1 and FERC Form No. 3-Q, Annual and Quarterly Reports, as well as PacifiCorp's OATT, prior Commission audit reports, and other relevant information in the Commission's eLibrary records system and on public web sites.

- *Regulatory Standards and Criteria* - Identified regulatory requirements, filings and criteria to evaluate PacifiCorp's compliance with each audit objective. These requirements and filings included Attachment H to PacifiCorp's OATT, and related filings to understand PacifiCorp's wholesale formula rate requirements the Commission imposed in its approval of PacifiCorp's wholesale formula rate. Also, reviewed Commission financial accounting and reporting requirements and other Commission orders relevant to the audit.

- *Data Collection and Data Requests* - Issued several formal data requests, supplemental site visit informational requests, and numerous emails with questions and requests for clarification to obtain information to support compliance tests and evaluation of compliance. This information pertained to PacifiCorp's corporate

structure, policies and procedures, accounting systems and data, financial and reporting activity, wholesale formula rate processes, procedures, and inputs, rate schedules and tariffs, internal audit, Board of Directors and Audit Committee meeting minutes, settlement agreements and contracts, FERC compliance program, and other pertinent information not publicly available. Audit staff used this information as the basis for compliance testing and evaluation.

- *Site Visits* - Conducted four site visits to PacifiCorp for testing in audit scope areas. The visits enabled audit staff to understand PacifiCorp's structure, activities, functions, systems, and the processes used in its operations. While on site, audit staff interviewed personnel with direct knowledge and involvement with activities in the audit scope areas about processes, procedures, operations, and preliminary observations, reviewed and discussed documented policies and procedures and observed accounting system functionalities.

- *Interviews and Teleconferences* - Held an opening conference with PacifiCorp to discuss audit objectives, scope, and process. Audit staff also held a closing conference about fieldwork completion and the extent of audit findings and recommendations. Audit staff conducted regular phone interviews and teleconferences with PacifiCorp employees to clarify and understand company policies, practices, and procedures relevant to the audit.

- *External Auditor Working Papers* – To substantiate audit staff's testing, reviewed PacifiCorp's external auditors, Deloitte & Touche LLP, working papers for PacifiCorp's financial reporting in the FERC Form No. 1 and relevant accounting to substantiate audit staff's testing in these areas.

- *Interoffice Outreach* - Conferred with Commission staff from other divisions within the Office of Enforcement, and with technical and legal staff from other Commission offices, including the Office of Energy Market Regulation (OEMR), who have knowledge and expertise about PacifiCorp's transmission system and regulatory history. Also, discussed with the Commission staff about audit development and potential compliance issues, to ensure audit report findings were written consistent with Commission precedent and policy.

Further, as detailed below, audit staff performed specific actions to facilitate the testing and evaluation of compliance with Commission requirements relevant to audit scope areas:

***Compliance with Wholesale Formula Rate***

Audit staff performed these actions to evaluate PacifiCorp's compliance with the requirements of its wholesale formula rate:

- *Formula Rate Schedules* - Reviewed Commission approved wholesale formula rate schedules and tariffs in effect for PacifiCorp as reported on page 106 of the PacifiCorp's FERC Form No. 1.

- *Commission Orders* - Reviewed initial and subsequent Commission orders accepting PacifiCorp's wholesale formula rate, including orders approving related settlements and PacifiCorp's OATT revision in Attachment H-1 for depreciation rates. Reviewed Commission orders for background information about specific cost treatments and unique inputs, and other matters disclosed as part of approving the derivation of PacifiCorp's wholesale formula rate.

- *Formula Rate Procedures* - Evaluated PacifiCorp's processes, procedures, and controls used for preparing and reviewing annual and true-up informational filings and their supporting work papers. Reviewed wholesale formula rate mechanics, such as annual informational filings, true-up informational filings, and summary report true-up informational filings associated with PacifiCorp's wholesale formula rate. Reviewed PacifiCorp's tariff and its Attachment H to determine the services rendered under the tariff.

- *Interviewed Employees Responsible* - Interviewed PacifiCorp employees responsible for calculating the wholesale formula rate and for providing data inputs into the rate. Assessed the level of oversight and controls to ensure complete and accurate wholesale formula rate inputs.

- *Formula Rate Reconciliation* - Reconciled the wholesale formula rate inputs to figures reported in the FERC Form No. 1. Evaluated the adequacy of disclosure for formula rate inputs not derived from the FERC Form No. 1.

- *Mathematical Accuracy* - Evaluated PacifiCorp's mathematical accuracy of computations entered into the wholesale formula rate to ensure all information was correctly entered. For example, audit staff reviewed supporting documentation for post-retirement other than pensions to verify amounts were correctly populated into the wholesale formula rate template.

- *Formula and Input Analysis* - Reconciled the components of the approved rate formula to the corresponding calculations in the annual rate filings. Analyzed and assessed PacifiCorp's compliance with Uniform System of Accounts and accounting treatment of select formula input. Reviewed the support behind allocation factors used in the wholesale formula rate to ensure the correct amounts were used in the calculations.

- *Formula Rate Billing Analysis* - Reviewed the accuracy and timeliness of wholesale formula rate customer billing, including refunds and surcharge billings resulting from formula rate true-ups.

***Compliance with Commission Accounting Regulations***

- *Accounting Process and Procedures* - Evaluated PacifiCorp's financial accounting processes, procedures, and internal controls to comply with Commission financial accounting regulations under 18 C.F.R. Part 101. Audit staff interviewed PacifiCorp employees about accounting practices, reviewed system processes for account assignments, and observed controls for achieving compliance with the Commission's Accounting Regulations.

- *Accounting Applications and Classifications* - Evaluated PacifiCorp's chart of accounts used during the audit period to determine if it was consistent with the Commission Accounting Regulations. Reviewed descriptions of accounting practices and tested examples for specific accounts in sample months to supporting material, and evaluated quality controls to ensure accounting classifications complied with the Commission's Accounting Regulations.

- *Accounting Systems* - Reviewed PacifiCorp's financial accounting systems to manage company financial records, such as systems for recording and tracking PacifiCorp's costs, including the general ledger, work order, expense and billing and accounts payable. Reviewed practices and procedures around the accounting cycle for charges and the mapping of those charges to FERC accounts.

- *Employee Time Tracking System* - Evaluated PacifiCorp's employee time-tracking system and internal controls, such as management reviews and budget variance procedures for employee time, and reviewed select time reports illustrating time charges to business units and the classification of work.

- *Project Tracking System* - Reviewed project tracking procedures for a project's life cycle, i.e., procurement, selection of cost allocators, tracking and billing of costs to affiliated companies, and system work order removal procedures.

- *Significant Accounting Matters* - Tested select accounts impacting the wholesale formula rate to ensure the nature of costs recorded in those accounts complied with the Commission's Accounting Regulations. For example, audit staff performed select testing of these accounting matters:

- *Transmission vs. Distribution* - Reviewed certain transmission operating and maintenance accounts to ensure costs related to transmission and no other functional expense accounts, such as distribution or production.

- *Administrative and General Expenses* - Tested select 900 series accounts to determine whether PacifiCorp recorded salaries, office supplies, outside services (e.g. consultant fees), pensions and employee benefits, and other administrative and general expenses consistent with account instructions.

- *Non-operating Expenses* - Examined summaries for above-the-line accounts to ensure PacifiCorp did not record non-operating expenses, such as political and charitable contributions in these operating expenses accounts. Examined the accounting for expenses for employment practices that judicial or administrative decrees found to be discriminatory to verify PacifiCorp recorded these activities to the proper non-operating expense account consistent with Commission policy.

- *Cost Allocations* - Examined support and tested the corporate and associated company allocation methodologies for recording shared service costs between affiliates, and billing and accounting of non-power goods and services provided amongst associated companies. For example, audit staff reviewed cost centers' shared-service allocation ratios and tested select cost centers to ensure PacifiCorp allocated and accounted for shared services correctly. Also reviewed affiliate billing procedures and select invoices to verify PacifiCorp recorded the proper amounts in accordance with those procedures.

- *Accumulated Deferred Income Taxes* - Reviewed a monthly summary of deferred taxes that flowed into the rate base component of the wholesale formula rate. Analyzed supporting documentation to evaluate how PacifiCorp calculated the deferred tax component and underlying accounting entries made to FERC deferred tax accounts (i.e., Accounts 190, 282, and 283). Evaluated PacifiCorp's method for associating depreciation on property and allocating percentages, its liberalized depreciation of Accounts 282 and 283, and the accounting impact relating to depreciation and recognition of income for select divested assets.

- *Income Taxes and Tax Allocation Agreements* - Evaluated PacifiCorp's consolidated income tax allocation share agreement and the tax payment structure between PacifiCorp and BHE, including the methodology used to allocate the tax benefits/burden. Reviewed supporting documentation to validate the calculation of tax accruals and deferred income taxes. Reviewed discrepancies found between deductions taken on PacifiCorp's

books and the Schedule M-1 of PacifiCorp's Federal income tax return (FF1120), which could affect the rate base adjustment worksheet of the wholesale formula rate.

- *Hedging Activities and Unrealized Gains/Losses* - Reviewed PacifiCorp's derivative instruments and hedging activities resulting in unrealized gains and losses and how these amounts factored into its rate of return for ratemaking and AFUDC purposes, and supporting journal entries to verify amounts were recorded consistent with Commission regulations.

- *Depreciation* - Evaluated PacifiCorp's monthly depreciation and amortization expense and supporting calculations to verify it used the proper accounts and recorded the correct amounts. Reviewed PacifiCorp's depreciation expense calculation to ensure it derived monthly depreciation expenses using approved depreciation rates on file with the Commission.

- *Pensions* - Reviewed descriptions of PacifiCorp's active pension plans, policies, procedures, and guidelines. Examined journal entries for pension expenses, funding, and liabilities to ensure it charged the appropriate accounts. Also evaluated PacifiCorp's rate-recovery mechanism to determine how PacifiCorp funded its pension plans, and the methodology PacifiCorp used to recover pension costs through rates.

- *Asset Retirement Obligations (ARO)* - Reviewed PacifiCorp's accounting treatment for costs recorded in select 300 series or plant-in-service accounts relating to AROs for compliance with Commission accounting regulations. Evaluated PacifiCorp's valuation methodology to record each ARO to ensure it recorded depreciation and accretion expense properly and did not recover those amounts in wholesale rates.

- *Contingent Liabilities* - Reviewed the Notes to Financial Statements in the FERC Form No. 1s and identified information about accruals for potential future obligations. Analyzed information on commitments and environmental and legal contingencies, and assessed whether these amounts affected wholesale rates.

- *Sale or Retirement of Business Assets* - Evaluated gains and losses resulting from the disposition of assets in Account 421.1, Gain on Disposition of Property, and reconciled the book depreciation and retirement amounts reported in the FERC Form No. 1 for assets in certain tax classes.

- *Subsidiary Accounting* - Reviewed the FERC Form No. 1, materials PacifiCorp provided, and publicly available information to determine

whether PacifiCorp controlled any wholly owned subsidiaries, and applied the equity method or consolidated method of accounting for subsidiary investments.

- *AFUDC* - Reviewed the company's AFUDC rate calculation for consistent application with Electric Plant Instruction No. 3. Validated PacifiCorp's methodology for determining the annual AFUDC rate to ensure it was based upon its own debt and equity book balances and to ensure the short term debt rate variance did not exceed 25 basis points. Reviewed work orders to confirm the company ceased accruing AFUDC upon in-service dates, periods of suspension, and abandonment. Examined the construction base component of its AFUDC accrual calculation to ensure it included amounts relating to construction activities and properly allocated overheads.

***Compliance with FERC Form No. 1 Reporting Requirements***

Audit staff performed the following actions to facilitate the testing and evaluation of compliance with Commission requirements relevant to the FERC Form No. 1:

- *Reporting Process and Procedures* - Audit staff evaluated PacifiCorp's financial reporting processes, procedures, and quality controls used to prepare FERC Form No. 1 and comply with Commission regulations in Part 141.

- *Financial Reporting Instructions* - Audit staff evaluated PacifiCorp's financial reporting to determine whether it complied with the account and page instructions of FERC Form No. 1.

- *Financial Statement Account Balances* - Audit staff tied the account balances reported in FERC Form No. 1 to PacifiCorp's books and records. To facilitate the review, audit staff reviewed selected transactions to confirm the balances.

- *Account Variance Analysis* - Audit staff performed variance analyses for accounts reported in FERC Form No. 1 with large balances, unusual activity, and/or significant fluctuations.

- *Notes to Financial Statements* - Audit staff reviewed the Notes to Financial Statements of FERC Form No. 1 for significant accounting matters, and followed up on these matters to understand financial statement and wholesale formula rate implications.

# IV. Findings and Recommendations

## 1. Storm Damage Accounting and Costs Recovery

PacifiCorp's accounting and wholesale formula rate billings for storm damage costs during the period of 2012 through 2015 were deficient as follows:

- PacifiCorp improperly overbilled storm damage costs to its merchant function and third-party wholesale customers that procured transmission services under PacifiCorp's OATT. This occurred because PacifiCorp improperly included actual plus estimated costs associated with the same storms in billings to its merchant and third-party wholesale customers. As a result, PacifiCorp overstated its wholesale transmission revenue requirement by approximately $6.9 million, which led to overbillings to third-party wholesale customers by approximately $1.1 million.

- PacifiCorp did not make refunds to its wholesale customers for the excessive storm damage revenues collected from its wholesale customers.

### Pertinent Guidance

18 C.F.R. 101, Account 924, Property Insurance, states in part:

> Recoveries from insurance companies or others for property damages shall be credited to the account charged with the cost of the damage. If the damaged property has been retired, the credit shall be to the appropriate account for accumulated provision for depreciation.

18 C.F.R. 101, Account 571, Maintenance of Overhead Lines, states in part:

> This account shall include the cost of labor, materials used and expenses incurred in maintenance of transmission plant, the book cost of which is includible in accounts 354, Towers and Fixtures, 355, Poles and Fixtures, 356, Overhead Conductors and Devices, 359, Roads and Trails.

### Background

PacifiCorp experienced a number of uninsured property damages due to wind, rain, ice, and snow storms. The storms caused power outages in PacifiCorp's generation, transmission, and distribution systems. To evaluate storm damage cost incurred by PacifiCorp and storm damage cost charged through wholesale formula rates, audit staff examined PacifiCorp's accounting policies, processes, and procedures, interviewed

employees responsible for implementing accounting practices, evaluated detailed accounting records and supporting documentation and analyzed PacifiCorp's Commission-jurisdictional wholesale formula rate filings and associated orders.

PacifiCorp's wholesale customers that take service under its OATT have written contracts in place that governs the transmission services offered by PacifiCorp. PacifiCorp's wholesale transmission customers include its merchant function as well as other wholesale customers.

*Accounting for Storm Damages*

PacifiCorp accounted for transmission-related storm damage costs using Account 571, Maintenance of Overhead Lines, and Account 924, Property Insurance. Actual storm damage costs were recorded in Account 571, while estimated costs for the storms were recorded in Account 924. Both Accounts 571 and 924 were used in PacifiCorp wholesale formula rates in determining billings to its merchant function and other wholesale customers. When a storm occurs, PacifiCorp paid storm damage costs and recovered such actual costs from wholesale customers through its wholesale formula rate by charges to Account 571. Also, PacifiCorp recovered estimated storm damage costs related to the same storm from its wholesale customers through charges to Account 924. From 2012 through 2015, PacifiCorp recorded $1,634,718 in Account 571 and $6,861,201 in Account 924.

*Wholesale Formula Rates Recovery of Storm Damage Costs*

Since 2012, PacifiCorp's wholesale formula rates have been determined pursuant to the directives of the formula manual in its OATT.[4] In accordance with the formula manual, balances appropriately accounted for in specific accounts may be includible in the derivation of wholesale formula rates charged. As mentioned above, PacifiCorp accounted for actual and estimated storm damage costs in Accounts 571 and 924, respectively. The amounts recorded in these accounts were included in the determination of wholesale formula rates billed to the company's merchant function and other wholesale customers. The table below shows the total amount collected for storm damage costs versus the actual storm damage costs incurred to repair and restore the transmission system.

[4] *See* PacifiCorp, Transmission OATT and Service Agreements, OATT Volume No. 11, Attachment H-2, Formula Rate Implementation Protocols (1.0.0).

| Storm Damage Operating and Maintenance Expense | 2012 | 2013 | 2014 | 2015 | Total |
|---|---|---|---|---|---|
| Actual expenses incurred on transmission system | 615,586 | 162,714 | 292,450 | 563,968 | 1,634,718 |
| Actual expenses collected through formula rate | 615,586 | 162,714 | 292,450 | 563,968 | 1,634,718 |
| Estimated expenses collected through formula rate | 1,505,666 | 1,598,713 | 1,747,354 | 2,009,468 | 6,861,201 |
| Total storm damages collected through formula rate | 2,121,252 | 1,761,427 | 2,039,804 | 2,573,436 | 8,495,919 |
| **Expenses over collected through formula rate** | **1,505,666** | **1,598,713** | **1,747,354** | **2,009,468** | **6,861,201** |

Audit staff point out that, PacifiCorp billed its merchant function and third-party wholesale customers for actual storm damage costs while also collecting estimated storm damage costs through its wholesale formula rates. Since PacifiCorp recovered from its merchant function and other wholesale customers the actual storm damage costs, there was no basis for PacifiCorp to also recover estimated storm damage costs from wholesale customers. Thus, PacifiCorp should have excluded estimated amounts for storm damage expenses in Account 924, subsequently allocated to the wholesale formula rates.

Audit staff evaluated through interviews and document reviews the coordination between departments within PacifiCorp. Audit staff is concerned that coordination between departments within PacifiCorp was not strong enough to prevent PacifiCorp from collecting both actual and estimated (over collection) storm damage costs through the wholesale formula rates. Strengthening the coordination between departments may have mitigated the overbilling of storm damage costs. As a result of PacifiCorp's accounting and wholesale transmission rate recovery practices, the company overstated its wholesale transmission revenue requirement by approximately $6.9 million from 2012 to 2015. This led to PacifiCorp overbilling its merchant function through inter-departmental billings by $5.8 million and third-party wholesale customers by $1.1 million.

**Recommendations**

We recommend PacifiCorp:

1. Refrain from recovering actual and estimated storm damage costs from wholesale customers associated with the same storm. Revise policies, procedures and practices to ensure the proper accounting procedures are employed to prevent the double collection of storm damage costs through the wholesale formula rates.

2. Revise wholesale formula rates development procedures to strengthen coordination between accounting and wholesale formula rates development departments.

3. Provide training to staff on the revised storm damage accounting and rate development methods. Also, develop a training program that supports the provision of periodic training in this area, as needed.

4. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate storm damage recoveries since 2012, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to be refunded; and (5) period(s) refunds will be made. Include the results of the analysis of transmission-related storm damage expenses in the refund amount.

5. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

6. Refund amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of Commission regulations.

**2. Mining Assets**

PacifiCorp inappropriately recovered from its wholesale customers the cost of production related mining assets through its wholesale formula rates. As a result, PacifiCorp overstated its wholesale transmission revenue requirement by approximately $3.7 million, which led to overbillings to third-party wholesale customers by approximately $600,000.

**Pertinent Guidance**

In *Ameren Corporation*, the Commission states in part:

> [It] has repeatedly held that it may order refunds for past periods where a utility has either misapplied a formula rate or otherwise charged rates contrary to the filed rate. The Commission has explained that, "in approving any formula rate, the Commission approves the formula itself, the algebraic equation used to calculate the rates. It does not approve the inputs into the formula or the charges resulting from the application of the inputs to the algebraic equation." Moreover, "[t]he Commission's long-standing precedent is that, under formula rates, parties have the right to challenge the inputs to or the implementation of the formula at whatever time they discover errors in the inputs to or implementation of the formula." The reason for permitting such challenges and related refunds is because "customers may not uncover errors in data or imprudent or otherwise inappropriate costs until well after the challenge period.[5]

PacifiCorp's OATT, Volume No. 11, Part IV. 36, Definitions, states in part:

> **Tariff** shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.[6]

**Background**

Deer Creek Mine was an underground mine owned by PacifiCorp. In addition, PacifiCorp owned a separate mineral lease license for lands adjacent to the Deer Creek

[5] *Ameren Corporation*, 147 FERC ¶ 61225, at P 27 (2014).

[6] PacifiCorp, Transmission OATT and Service Agreements, OATT Volume No. 11, Part IV.36, Definitions (1.0.0).

Mine, through its 100 percent owned subsidiary Fossil Rock Fuels, LLC. The mine was operated by Energy West Mining Company, also a subsidiary of PacifiCorp. PacifiCorp's ownership interests in Fossil Rock Fuel and Energy West Mining Company were recorded based on the equity method as required by the Commission's accounting regulations.

PacifiCorp's ownership of the tangible and intangible assets of the Deer Creek Mine was recorded on the balance sheet of PacifiCorp in Account 399, Other Tangible Property, and Account 303, Miscellaneous Intangible Plant, respectively. The depreciation component of the mining assets were recorded in Account 151, Fuel Stock, as part of coal inventory.

In 2013, PacifiCorp's wholesale formula rate was approved by the Commission and was retroactive to the 2012 rate year. The settlement agreement added an Attachment H to PacifiCorp's OATT which included wholesale formula rates for transmission services. The Attachment H included the protocols used by PacifiCorp to compute its annual wholesale transmission revenue requirement. Per the wholesale formula rates, General Plant in Service is included in transmission rate base and in developing allocators based on gross plant and net plant. Audit staff reviewed PacifiCorp's wholesale formula rates for 2012 through 2015 and determined that PacifiCorp inappropriately recovered the cost of mining assets recorded in Account 399 from wholesale customers.

PacifiCorp's wholesale formula rates tariff was developed to recover the cost for transmission service provided by PacifiCorp. Additionally, PacifiCorp's wholesale formula rate was not developed to permit the recovery of production assets exclusively used to serve its production function. Audit staff determined that PacifiCorp's mining assets served only the production function and had no relevance to the transmission service provided under PacifiCorp's wholesale formula rates tariff; hence the cost related to mining assets should not be recovered from wholesale customers.

Audit staff analysis of PacifiCorp's inclusion of mining assets in wholesale transmission rate base and gross and net plant allocators determined that PacifiCorp overstated its wholesale transmission revenue requirement by approximately $3.7 million, which led to PacifiCorp overbilling its merchant function through inter-departmental billings by approximately $3.1 million and third-party wholesale customers by approximately $600,000.

**Recommendations**

We recommend PacifiCorp:

7. Revise procedures for computing the annual wholesale transmission revenue requirement and billing to wholesale customers by ensuring that it excludes cost of mining assets from the wholesale formula rates.

8. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate cost of mining asset recoveries that resulted from the inclusion of mining assets in the wholesale formula rates base since 2012, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to be refunded; and (5) period(s) refunds will be made.

9. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

10. Refund amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of Commission regulations.

### 3. Amortization of Regulatory Assets

PacifiCorp inappropriately included amortization of regulatory assets in its wholesale formula rates. As a result, PacifiCorp overstated its wholesale transmission revenue requirement by approximately $800,000, which led to overbillings to third-party wholesale customers of approximately $100,000.

**Pertinent Guidance**

PacifiCorp's OATT states in part:

> All regulatory asset amortizations shall be excluded from the calculation of the Annual Transmission Revenue Requirement (ATRR) and charges under the Formula Rate, unless approved by the Commission.[7]

18 C.F.R. Part 101, Account 920, Administrative and General Salaries, states in part:

> A. This account shall include the compensation (salaries, bonuses, and other consideration for services, but not including directors' fees) of officers, executives, and other employees of the utility properly chargeable to utility operations and not chargeable directly to a particular operating function.

18 C.F.R. Part 101, Account 925, Injuries and Damages, states in part:

> A. This account shall include the cost of insurance or reserve accruals to protect the utility against injuries and damages claims of employees or others, losses of such character not covered by insurance, and expenses incurred in settlement of injuries and damages claims. For Major utilities, it shall also include the cost of labor and related supplies and expenses incurred in injuries and damages activities.

[7] PacifiCorp, Explanatory Statement in Support of Settlement, Docket No. ER11-3643, Section 3.4.2.9 (filed on Feb. 22, 2013) (Approved by the Commission under *PacifiCorp*, 143 FERC ¶ 61,162.)

18 C.F.R. Part 101, Account 926, Employee Pensions and Benefits, states in part:

> This account shall include pensions paid to or on behalf of retired employees, or accruals to provide for pensions, or payments for the purchase of annuities for this purpose, when the utility has definitely, by contract, committed itself to a pension plan under which the pension funds are irrevocably devoted to pension purposes, and payments for employee accident, sickness, hospital, and death benefits, or insurance thereof. This also includes expenses incurred in medical, educational, or recreational activities for the benefit of employees, and administrative expenses in connection with employee pensions and benefits.

**Background**

PacifiCorp provided electric utility services to customers in six retail jurisdictions. Due to ratemaking actions of these retail jurisdictions, PacifiCorp created regulatory assets to recover the retail portion of certain expense items in retail rates. Audit staff reviewed items recorded in PacifiCorp's Account 182.3, Other Regulatory Assets, to determine if items recorded in the account were appropriately accounted for and approved in accordance with Commission accounting regulations and tariff requirements. In addition, audit staff reviewed regulatory assets to understand the effect of regulatory assets on PacifiCorp wholesale transmission revenue requirement.

Audit staff's review of Account 182.3, found that PacifiCorp recorded several regulatory assets based on ratemaking actions of state regulators. PacifiCorp did not seek Commission approval for any of the regulatory assets included in Account 182.3. Audit staff found that amortization of four regulatory assets impacted wholesale formula rates development.

*Environmental damages amortization*

PacifiCorp incurred environmental damage costs related to 33 properties it owned or adjacent to properties it owned due to local, state and federal environmental regulations. Some of the locations were previously owned by PacifiCorp and subsequently sold prior to the audit period. PacifiCorp represented that much of the environmental damage were attributable to utility operations of several companies it acquired, some legacy sites of which were subsequently sold by those companies. The properties owned by PacifiCorp were used in its production and distribution functions. The environmental damage costs were approved by several state commissions for retail rate recovery over ten years. PacifiCorp recorded the cost of environmental damages as regulatory assets in Account 182.3 and amortized the regulatory asset to Account 925, Injuries and Damages.

*Prepaid Pension, PBOP and Injuries and Damages amortization*

The regulatory assets recorded in Account 182.3 included regulatory assets associated with prepaid pensions and prepaid postretirement benefits approved for recovery by several of PacifiCorp's retail regulators.[8] PacifiCorp also recorded a regulatory asset for injuries and damages claims in the state of Oregon based on an Oregon Public Utility Commission order. PacifiCorp recorded amortization of the regulatory assets for prepaid pensions and postretirement benefits in Account 920, Administrative and General Salaries, and amortization of the regulatory asset for injuries and damages in Account 925, based on recovery of the regulatory assets in retail rates.

*Accounting for amortization of regulatory assets*

Audit staff found that PacifiCorp's accounting for amortization of environmental damages regulatory asset in Account 925 was inconsistent with Commission accounting regulations. Account 925 should include the cost of insurance or reserve accruals to protect the utility against injuries and damages claims of employees or others, or losses of such character not covered by insurance. Audit staff believes that PacifiCorp's environmental damages did not meet the character of losses included in Account 925. PacifiCorp should have amortized the amounts of the environmental damages related regulatory assets recovered in its retail rates to appropriate functional production or distribution operating and maintenance expense accounts.

Audit staff found that PacifiCorp's accounting for amortization of prepaid pension and postretirement benefit regulatory assets in Account 920 was inconsistent with Commission accounting regulations. Pensions and postretirement benefits should be recorded in Account 926 under the Commission accounting regulations. Also, PacifiCorp should have recorded the amortization of pension and postretirement benefit costs to Account 926, Employee Pensions and Benefits, not Account 920.

*Wholesale formula rates recovery of amortization of regulatory assets*

PacifiCorp's settlement agreement and wholesale formula rates protocols approved by the Commission in Docket No. ER11-3643 included allocable costs of items recorded in Account 920 and Account 925, to derive the wholesale transmission revenue

[8] *See Application for an Accounting Order Regarding Pension Curtailment*, Order No. 08-598 (Oregon Public Utility Commission, Dec. 24, 2008); *Accounting Order Regarding Pension Curtailment and Pension Measurement Date Change*, Docket No. 08-035-93 (Utah Public Service Commission, Feb. 4, 2009).

requirement calculation, by way of a wages and salary allocator.[9] However, Section 3.4.2.9 of PacifiCorp's settlement agreement stated that, in part, all regulatory asset amortizations should be excluded from the calculation of the wholesale transmission revenue requirement and charges under the wholesale formula rates, unless approved by the Commission. Based on the fact that PacifiCorp's regulatory assets for prepaid pensions, prepaid postretirement benefits, environmental damages, and injuries and damages were not approved by the Commission, these amounts should not have been included in the wholesale transmission revenue requirement and billings to wholesale customers.

PacifiCorp's inappropriate inclusion of the regulatory assets' amortization into the wholesale transmission expenses overstated the wholesale transmission revenue requirement by approximately $800,000 from 2012 through 2015, which led to PacifiCorp overbilling its merchant function through inter-departmental billings by approximately $700,000 and other third-party wholesale customers by approximately $100,000.

**Recommendations**

We recommend PacifiCorp:

11. Revise accounting procedures to record pensions, and postretirement regulatory asset amortizations in Account 926.

12. Revise accounting procedures to exclude amortization of environmental damages regulatory assets to Account 925, and record amortization of amounts recovered in retail rates in appropriate functional operating and maintenance accounts.

13. Provide training to staff on the revised regulatory assets accounting and rate development methods. Also, develop a training program that supports the provision of periodic training in this area, as needed.

14. Record correcting entries to reclassify pensions, and postretirement regulatory assets amortization from Account 920 to Account 926.

15. Record correcting entries to reclassify environmental damages amortization from Account 925 and record the amounts recovered from retail rates in appropriate functional operating and maintenance accounts.

[9] PacifiCorp, Transmission OATT and Service Agreements, OATT Volume No. 11, Attachment H-1 (8.1.0), Appendix A.

16. Revise procedures for computing wholesale formula rates billings to wholesale customers to exclude amortization of regulatory assets which were not approved by the Commission.

17. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate regulatory asset amortizations which were included in wholesale formula rates and the refunds resulting from the inclusion of those regulatory asset amortizations in the wholesale formula rates, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to be refunded and (5) period(s) refunds will be made.

18. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

19. Refund amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of Commission regulations.

## 4. Injuries and Damages Accounting and Costs Recovery

PacifiCorp improperly classified injuries and damages accruals and recovered those costs through its wholesale formula rates when it had insurance policies to cover the cost of those damages. As a result, PacifiCorp overstated its wholesale transmission revenue requirement by approximately $2.9 million, which led to overbillings to third-party wholesale customers by approximately $400,000.

### Pertinent Guidance

18 C.F.R. 101, Account 925, Injuries and Damages, states in part:

> A. This account shall include the cost of insurance or reserve accruals to protect the utility against injuries and damages claims of employees or others, losses of such character not covered by insurance, and expenses incurred in settlement of injuries and damages claims. For Major utilities, it shall also include the cost of labor and related supplies and expenses incurred in injuries and damages activities.
>
> Reimbursements from insurance companies or others for expenses charged hereto on account of injuries and damages and insurance dividends or refunds shall be credited to this account.

18 C.F.R. Part 101, Account 426.5, Other Deductions, states in part:

> This account shall include other miscellaneous expenses which are non-operating in nature, but which are properly deductible before determining total income before interest charges.

18 C.F.R. Part 101, General Instruction No. 2, Records, states in part:

> A. Each utility shall keep its books of account, and all other books, records, and memoranda which support the entries in such books of account so as to be able to furnish readily full information as to any item included in any account. Each entry shall be supported by such detailed information as will permit ready identification, analysis, and verification of all facts relevant thereto.
>
> B. The books and records referred to herein include not only accounting records in a limited technical sense, but all other records, such as minute books, stock books, reports, correspondence, memoranda, etc., which may be useful in developing the history of or facts regarding any transaction.

**Background**

PacifiCorp operates in many western states where the frequency of wildfires has been high. PacifiCorp has historically had a significant amount of insurance coverage, provided by multiple insurers due to the potential for injuries and damages claims arising from wildfire and other perils of operating its electric system. PacifiCorp's insurance was organized on an excess liability structure with multiple tiers. The cumulative excess liability insurance provided by the insurers totaled $250 million in protection to PacifiCorp, with a $3 million deductible, from August 28, 2011 to October 1, 2012.

PacifiCorp's liability insurance program was administered by its indirect parent company, Berkshire Hathaway Energy Company (BHE). BHE, through a third-party provider, assigned the relevant insurance premium costs to PacifiCorp and the other affiliates. PacifiCorp paid approximately $2 million in insurance premiums for the August 28, 2011 to October 1, 2012 insurance period, and allocated a portion of this insurance premium to wholesale customers in developing wholesale formula rates.

*Wildfires*

PacifiCorp was exposed to two wildfire claims in 2012 during the policy period from August 28, 2011 to October 1, 2012. A claim on PacifiCorp by an unrelated third-party for damages resulting from a 2009 fire, known as "Williams Creek fire" on Umpqua National Forest land in Oregon, followed by another claim notice for the same fire by the US Forest Service, United States Department of Agriculture. In addition, several claims were made in 2012 against PacifiCorp for a second fire at Wood Hollow, Sanpete County, Utah in June 2012. Audit staff determined that the damages from the Wood Hollow wild fire would significantly exceed damages from the Williams Creek fire. Investigations and claim negotiations related to both wildfires (Williams Creek and Wood Hollow) have not been completed, as of the date of this audit report.

*Chevron Oil Pipeline Leak*

PacifiCorp was exposed to another damage claim in 2012, when the Pipeline and Hazardous Materials Safety Administration concluded that an electrical arc from an electrical transmission station owned by PacifiCorp created a hole in a pipeline in June 2010. The pipeline was owned by Chevron Pipe Line Company. The damage from the electrical arc caused oil to leak into Red Butte Creek and migrated into the Liberty Park pond in the foothills of Salt Lake City, Utah.

*Accounting for Injuries and Damages*

PacifiCorp's legal team met quarterly, to evaluate pending liability claims against the company. The legal team produced a report called the quarterly litigation report

(QLR). The QLR provided the legal team's assessment of PacifiCorp's exposure to potential losses arising from each liability claim. PacifiCorp's accounting staff made appropriate accounting entries based on the QLR produced by the legal team.

Based on the QLR for the Williams's Creek and Wood Hollow fires and Chevron Oil Pipeline leak, PacifiCorp recorded the following accruals in Account 925, Injuries and Damages, with corresponding credits in Account 228.2, Accumulated Provision for Injuries and Damages:

Expenses recorded in Account 925 for wildfires and oil leak

| Expenses | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|
| Wildfires and Oil Leak | 36,427,396 | 29,238,276 | (33,495,311) | (5,118,064) |

PacifiCorp had insurance to cover the losses from the Wood Hollow fire and Chevron Oil Pipeline leak. However, even though it had insurance policies in 2012 to cover the losses less the deductible due to the fire and oil leak, PacifiCorp recorded an accrual on its books for the full amount of the losses, which included the $3 million deductible for each loss. During audit staff's several interviews, PacifiCorp represented that a management decision not to reduce the accrual for any insurance receivable was made by PacifiCorp's Executive Management in 2012 when they decided not to seek insurance reimbursement for damages covered by the insurance policies. PacifiCorp represented that, it did not retain any analyses, rationale or written directives to support the accounting decision for not recording insurance receivables. Since PacifiCorp's executive management decided not to seek insurance reimbursement for damages covered by existing insurance policies, it should have recorded the accrual for the covered damage amounts in Account 426.5, Other Deductions, instead of Account 925.

PacifiCorp began accruing for the Wood Hollow fire insurance recoveries from insurance companies in 2014. In 2015, PacifiCorp received insurance reimbursement from its policy holders for the Wood Hollow fire claims, directly settled and paid by PacifiCorp to its claimants. In addition, PacifiCorp recorded additional offsets in 2014 for the excess Wood Hollow fire expenses recorded in Account 925 in 2012 and 2013. However, PacifiCorp did not record any insurance reimbursement and reduced the accrual related to the Chevron Oil Pipeline leak during this period.

*Wholesale Formula Rates Impact*

PacifiCorp had insurance to cover losses caused by the Wood Hollow fire and Chevron Oil Pipeline leak. The insurance premiums for those insurance policies were recorded in Account 925, and an allocated portion of the premiums was collected from wholesale customers. During audit staff's interviews, PacifiCorp could not provide audit

staff with any satisfactory evidence to support the collection of damages in excess of coverage deductible in 2012 and 2013 was approved by the Commission. Hence, PacifiCorp should not have collected the damages from the Wood Hollow fire and Chevron Oil Pipeline leak in 2012 and 2013, except for the insurance deductible amounts paid and stipulated in the insurance policies, from wholesale customers. Even though PacifiCorp credited the excess amount related to the Wood Hollow fire that was inappropriately collected in 2012 and 2013 to wholesale customers through its wholesale formula rates in 2014, audit staff points out that loads and customer groups in 2012 and 2013 were different from 2014; hence, the wrong customer groups may have been refunded the inappropriately collected funds.

Audit staff is concerned that PacifiCorp recovered wildfire and oil leak damages covered by insurance policies from the wholesale customers, who paid the insurance premiums. Audit staff did not find sufficient evident that shows that, wholesale customers under the Commission's jurisdiction, and other wholesale formula rates stakeholders were informed of PacifiCorp's decision not to seek insurance recovery for the wildfire and oil leak damages.

Due to PacifiCorp's accounting and wholesale formula rates practices, it inappropriately collected approximately $2.9 million through its wholesale transmission revenue requirement in 2012 and 2013, which led to PacifiCorp overbilling its merchant function through inter-departmental billings by approximately $2.5 million and third-party wholesale customers by approximately $400,000.

**Recommendations**

We recommend PacifiCorp:

20. Revise policies, procedures and practices to book accruals for covered damage amounts in Account 426.5 when management makes a decision not to seek insurance recoveries for damages covered by insurance.

21. Provide training to staff on the revised injuries and damages expenses covered by insurance accounting and rate development methods. Also, develop a training program that supports the provision of periodic training in this area, as needed.

22. Submit a refund analysis within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate injuries and damages recoveries that resulted from the inclusion of excessive estimated expenses in the wholesale formula rates since 2012, plus interest; (2) determinative

components of the refund; (3) refund method; (4) customers to be refunded; and (5) period(s) refunds will be made.

23. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

24. Refund amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of Commission regulations.

## 5. Allowance for Funds Used During Construction

PacifiCorp's methods for calculating Allowance for Funds Used During Construction (AFUDC) rate was deficient as follows:

- PacifiCorp inappropriately included letter of credit fees (up-front and quarterly) as part of short term debt interest expense to compute AFUDC rate.

- PacifiCorp inappropriately included Unappropriated Undistributed Subsidiary Earnings as part of the equity component for the purpose of computing AFUDC rate.

- PacifiCorp inappropriately included Accumulated Other Comprehensive Income (AOCI) as part of the equity component for the purpose of computing AFUDC rate in 2013.

As a result, PacifiCorp over accrued Allowance for Funds Used During Construction by approximately $6.8 million for 2013 through 2015. PacifiCorp overbilled wholesale customers for the excessive AFUDC costs included in utility plant that was included in wholesale formula rates determinations through rate base and depreciation charges.

**Pertinent Guidance**

Order No. 561, states in part:

> The balances of long-term debt, preferred stock, and common equity for use in the formula for the current year will be the balances in such accounts at the end of the prior year…
>
> We agree that in some instances, such items could properly be considered in determining the effective cost rate for short-term debt for use in the formula. However, primarily because of measurement problems, we do not believe that specific recognition should be given in the general rule. Instead, where an individual company has a written agreement and can support the fact that compensating balances and commitment fees are necessary in order to obtain favorable short-term financing and are not considered in its rate proceedings, we will permit an adjustment to the nominal short-term interest rates to reflect this additional cost.[10]

[10] *Amendments To Uniform System of Accounts for Public Utilities and Licensees and for Natural Gas Companies (Classes A, B, C and D) to Provide for the Determination of Rate for Computing the Allowance for Funds Used During*

18 C.F.R. Part 101, Electric Plant Instructions 3(A)(17), Allowance for Funds Used during Construction, states in part:

> Allowance for funds used during construction includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds.
>
> The rates shall be determined annually. The balances for long-term debt, preferred stock and common equity shall be the actual book balances as of the end of the prior year.

Order No. 469, states in part:

> It will continue to be the Commission's policy that the undistributed earnings of subsidiaries are to be excluded from the common stockholder's equity in determining rate of return.[11]

18 C.F.R. Part 101, General Instruction No. 23(C), Accounting for Other Comprehensive Income, states:

> When it is probable that an item of other comprehensive income will be included in the development of cost-of-service rates in subsequent periods, that amount of unrealized losses or gains will be recorded in Accounts 182.3 or 254 as appropriate.

**Background**

*Letter of Credit Facility*

PacifiCorp entered into two separate letter of credit agreements, in 2012 and 2013, for $600 million each. The terms of each agreement required PacifiCorp to pay an up-front fee in addition to quarterly interest payments on the unused balance at the end of

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*Construction and Revision of Certain Schedule Pages of FPC Reports*, Order No. 561, 57 FPC 608, at 610-611 (1977), *order clarifying orders,* Order No. 561-A, 2 FPC ¶ 1340 (1977).

[11] *Revisions in Uniform System of Accounts, and Annual Report Forms No. 1 and No. 2 to Adopt the Equity Method of Accounting for Long-Term Investments in Subsidiaries*, Order No. 469, 49 FPC 326, at 327 (1973).

each quarter. During 2012 and 2013, PacifiCorp paid approximately $3.6 million for upfront fees and approximately $3.3 million for quarterly interest payments. When PacifiCorp used the letter of credit, it was charged interest on the amount outstanding each month until PacifiCorp paid off the outstanding balance.

PacifiCorp accounted for the upfront fees and quarterly interest payments as well as the monthly interest payments for the credit balances outstanding by debiting Account 431, Other Interest Expense, and crediting Account 131, Cash.

Audit staff reviewed the individual components and calculations of PacifiCorp's AFUDC rate to determine whether PacifiCorp was in compliance with Commission accounting requirements. Audit staff determined that the components of short term interest expense included up-front fees and quarterly interest payments for the two $600 million letter of credit agreements obtained by PacifiCorp in 2012 and 2013. By including up-front fees and quarterly interest payments on unused credit balances, PacifiCorp's short term interest component of AFUDC rate calculation was overstated during the audit period. The table below shows appropriate short-term AFUDC rates developed in compliance with the Commission regulations and the AFUDC rates used by PacifiCorp:

Short-term AFUDC capitalization rate overstatement

| Year | Appropriate Rate | Rate Used by PacifiCorp | Rate Overstatement |
|---|---|---|---|
| 2013 | 0.31% | 15.92% | 15.61% |
| 2014 | 0.26% | 15.50% | 15.24% |
| 2015 | 0.49% | 3.89% | 3.40% |

Audit staff noted that, the Commission in Order No. 561[12] and Order No. 561-A[13] stated that, in order to include compensating balance and commitment fees in the

[12] In Order No. 561, the Commission stated that, "we do not believe that specific recognition should be given in the general rule. Instead, where an individual company has a written agreement and can support the fact that compensating balances and commitment fees are necessary in order to obtain favorable short-term financing and are not considered in its rate proceedings, we will permit an adjustment to the nominal short-term interest rates to reflect this additional cost." 57 FPC 608 at 5.

[13] Order No. 561-A, the commission stated that "Order No. 561 neither changes the Commission's policy with respect to treatment of short-term debt in capitalization used for rate of return purposes nor does it grant blanket approval for recognition of compensating balances and commitment fees in costing short-term debt. The burden of

short term debt interest component for AFUDC rate computation, an entity must obtain Commission approval. PacifiCorp did not provide audit staff with any evidence it obtained Commission approval to include these costs in its AFUDC rates calculation.

*Equity component of AFUDC rate*

Audit staff's examination of the equity component that was included in PacifiCorp's AFUDC rate calculation revealed that PacifiCorp incorrectly used balances from Account 219, Accumulated Other Comprehensive Income, during 2013, and Account 216.1, Unappropriated Undistributed Subsidiary Earnings, in the equity component of the AFUDC rate calculation. Account 219's balance represented an unrealized loss attributable to a Senior Executive Retirement Plan. In addition, PacifiCorp used a different amount from what was reported on it FERC Form No. 1 for Account 201, Common Stock Issued, Account 211, Miscellaneous Paid-In Capital, and Account 216, Unappropriated Retained Earnings, in its equity component for computing the AFUDC rate during the audit period, instead of using the amounts as reported on its FERC Form No.1.

AFUDC includes the net cost of borrowed funds used for construction purposes and an allowed rate on other funds. Since the gains and losses in Account 219 were unrealized, and amounts in Account 216.1 were undistributed by the subsidiaries and therefore not available to finance construction, those amounts should not have been considered as funds available for construction in deriving the rates used in AFUDC. In Order No. 469 the Commission stated that undistributed earnings of subsidiaries are to be excluded from the common stockholder's equity in determining rate of return. Additionally, the Commission's accounting regulations require the use of actual book balances as of the end of the previous year in the appropriate equity accounts when computing the AFUDC rate.

Since PacifiCorp did not seek or obtain Commission approval to include commitment fees in its AFUDC calculation or to deviate from the appropriate method for computing the AFUDC rate, it was inappropriate for PacifiCorp to include these amounts in its AFUDC rate calculation.

Audit staff's review of PacifiCorp's projects under construction showed that transmission projects represented approximately $106 million or 38 percent of the total AFUDC accrued during 2013 through 2015. As a result of PacifiCorp's deviation from the appropriate method for computing AFUDC rate, PacifiCorp over-accrued AFUDC by

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proof is upon the companies to justify such items before they will be permitted." 2 FPC ¶ 1340 at 1342.

approximately $6.8 million for all projects, including transmission projects, which led to overbilling its merchant function and third-party wholesale customers.

**Recommendations**

We recommend PacifiCorp:

25. Revise its procedures to ensure its AFUDC rate calculation is consistent with Order No. 561 and other applicable Commission requirements.

26. Revise its procedures to ensure that Account 216.1 is excluded from equity components used to derive AFUDC rate.

27. Revise its procedures to ensure that the amounts reported on the FERC Form No. 1 are used to compute AFUDC rate.

28. Provide training to staff on the revised AFUDC accounting and rate calculation method. Also, develop a training program that supports the provision of periodic training in this area, as needed.

29. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds to wholesale customers base since 2012, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to be refunded; and (5) period(s) refunds will be made.

30. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

31. Refund amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of Commission regulations.

## 6. Asset Retirement Obligations

PacifiCorp's accounting and rate treatment of Asset Retirement Obligations (ARO) were deficient as follows:

- PacifiCorp inappropriately excluded accumulated depreciation amounts removed from Account 108, Accumulated Provision for Depreciation of Electric Utility Plant, to implement ARO accounting in the wholesale formula rates determinations. As a result, PacifiCorp understated its wholesale transmission revenue requirement which led to under-billings to its wholesale customers through its wholesale formula rates.

- PacifiCorp inappropriately included estimated future asset retirement costs recorded in General Plant in its wholesale formula rate base. As a result, PacifiCorp overstated its wholesale transmission revenue requirement, which led to overbillings to its wholesale customers.

As a result of the deficiencies, PacifiCorp under-billed its wholesale customers through its wholesale formula rates.

**Pertinent Guidance**

18 C.F.R. § 35.18, Asset Retirement Obligations, states in part:

A. …all cost components related to asset retirement obligations that would impact the calculation of rate base, such as electric plant and related accumulated depreciation and accumulated deferred income taxes, may not be reflected in rates and must be removed from the rate base calculation through a single adjustment.

B. A public utility that has recorded asset retirement obligations on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligation-related cost components from the cost of service supporting its proposed rates.

Order No. 631 states:

After considering the comments, the Commission will grant jurisdictional entities the authority to adjust accounts 108, 110 and 253 to properly recognize and record the liabilities for legal retirement obligations for existing assets, the asset retirement costs and related accumulated depreciation on the capitalized costs when the amounts that would otherwise

be included in net income determinations meet the criteria for recognition as regulatory asset or liability.[14]

**Background**

In Order No. 631, the Commission granted authority to utilities under its jurisdiction to make transition entries to reclassify the excess or shortfall of depreciation recorded in Account 108 from prior cost of removal accounting over the accumulated depreciation that would have been recorded under SFAS No. 143[15] to Account 254, Other Regulatory Liabilities, or Account 182.3, Other Regulatory Assets, as appropriate. The Commission's rate regulations enacted by Order No. 631[16] required jurisdictional utilities to exclude the impact of all ARO-related accounting including cost components from rate determinations unless they sought and received approval to include ARO in rates. Under Order No. 631, PacifiCorp recorded certain accounting entries to transition from prior cost of removal accounting to ARO accounting for assets with legal retirement obligations.

*Account 108 Removals*

Based on Order No. 631, PacifiCorp made transition entries to debit approximately $11 million to Account 108 as excess depreciation and credited the same amount to Account 254. Also, PacifiCorp debited an additional $11 million to Account 108 and credited Account 254 following issuance of FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations. PacifiCorp in total removed approximately $22 million in transition entries from Account 108 pursuant to Commission Order No. 631.

Audit staff reviewed PacifiCorp's wholesale formula rates inputs and supporting worksheets and found that the accumulated depreciation amounts removed from Account 108 to implement ARO accounting requirements were excluded from wholesale formula rates determinations. PacifiCorp neither sought nor received approval from the Commission to exclude the accumulated depreciation balances from rates. PacifiCorp should have included the $22 million of accumulated depreciation in Account 108

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[14] *Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations*, Order No. 631, FERC Stats. & Regs. ¶ 31,142, at P 30, *order on reh'g*, Order No. 631-A, 104 FERC ¶ 61,183 (2003).

[15] *Accounting for Asset Retirement Obligations*, Statement of Financial Accounting Standards No. 143 (Fin. Accounting Standards Bd. 2001); *see* also Accounting for Conditional Asset Retirement Obligations – An Interpretation of FASB Statement No. 143, FASB Interpretation No. 47 (Fin. Accounting Standards Bd. 2005).

[16] 18 C.F.R. § 35.18, Asset Retirement Obligations.

balances used in its wholesale formula rates to eliminate the impact of PacifiCorp's ARO accounting on rate determinations as required by the Commission's rate regulations.

*General Plant AROs*

PacifiCorp recorded the asset retirement costs and liabilities as debits in Account 101 and credits in Account 230, Asset Retirement Obligations. PacifiCorp included in wholesale formula rate base the asset retirement costs recorded in Account 101 for general plant in service, resulting in an increase in wholesale transmission rate base. By including asset retirement costs in rate base, PacifiCorp overstated its wholesale transmission revenue requirement, which led to overbillings to its merchant function and other wholesale customers.

In addition, PacifiCorp's inappropriate exclusion of the accounting effect of Order No. 631 from its wholesale formula rates impacted the derivation of the account balances allocated to wholesale formula rates using net plant ratios. Also, inclusion of asset retirement costs in plant in service impacted the net plant and gross plant allocators. Based on PacifiCorp's inappropriate rate treatment, it under-billed it's merchant function and third-party wholesale customers since 2012.

**Recommendations**

We recommend PacifiCorp:

32. Revise existing accounting and rate development procedures and practices to ensure all ARO-related accounting effects and associated adjustments are excluded from wholesale formula rates determinations.

7. **Accounting for Coal Settlement Costs**

PacifiCorp incorrectly accounted for amortization of two coal settlement payments in Account 151, Fuel Stock, instead of Account 501, Fuel.

**Pertinent Guidance**

In *Kentucky Utilities Company*, the Commission notes:

> [T]hat the purpose of Account 151 is to accumulate the cost of fuel on hand, whereas, buyout costs are for the purpose of terminating a contract to purchase future coal. Buyout costs would therefore be includable in Account 151 only to the extent that we were to interpret our accounting regulations to contemplate that costs of future fuel purchases should include some portion of previously incurred buyout costs. We have not so interpreted our accounting regulation in the past, nor do we believe that it would be wise to do so here. We believe that buyout costs should be expended as incurred or, in the event that rate recognition is given in an appropriate proceeding, amortized to expense from a deferred charge account consistent with the rate recognition.[17]

18 C.F.R. § 35.14(a)(6), provides that,

The cost of fossil fuel shall include no items other than those in Account 151.

18 C.F.R. Part 101, Account 151, Fuel Stock (Major Only), states in part:

This account shall include the following book cost of fuel on hand:

*Items*

1. Invoice price of fuel less any cash or other discounts
2. Freight, switching, …

18 C.F.R. Part 101, Account 501, Fuel, states in part:

A. This account shall include the cost of fuel used in the production of steam for the generation of electricity, including expenses in unloading fuel from the shipping media and handling thereof up to the point where the fuel enters the first boiler plant bunker, hopper, bucket, tank or holder of the boiler-

[17] *Kentucky Utilities Company*, 45 FERC ¶ 61,409, at P 4 n.16 (1988).

> house structure. Records shall be maintained to show the quantity, B.t.u. content and cost of each type of fuel used.
>
> 18 C.F.R. Part 101, Account 186, Miscellaneous Deferred Debits, states:
>
> For Major utilities, this account shall include all debits not elsewhere provided for, such as miscellaneous work in progress, and unusual or extraordinary expenses, not included in other accounts, which are in process of amortization and items the proper final disposition of which is uncertain.

**Background**

PacifiCorp entered into two separate coal supply contracts to provide coal to its Wyodak and Naughton coal generation plants. Chevron Mining Inc. supplied coal to the Naughton plant and Wyodak Resources Development Corporation (Wyodak Resources) supplied coal to PacifiCorp's Wyodak generation plant. Due to pricing and contract disputes, PacifiCorp renegotiated the coal supply contracts with Chevron Mining Inc. (Naughton contract) and Wyodak Resources (Wyodak contract).

*Naughton Contract*

The Naughton contract between Chevron Mining Inc. and PacifiCorp was entered into in 1992 and was scheduled to terminate on December 31, 2016. The Naughton contract included market price reopeners. PacifiCorp renegotiated a new coal contract with Chevron Mining, Inc. to eliminate the market price reopener provision in the Naughton contract during 2010. As part of the settlement to renegotiate the original Naughton contract, PacifiCorp made a one-time payment upon execution of the settlement agreement. Per analysis performed by PacifiCorp, the renegotiated contract provided millions of dollars in cost savings on a net present value basis to customers through a lower cost of coal.

The one-time payment made to Chevron Mining Inc. by PacifiCorp was recorded by a debit to Account 186, Miscellaneous Deferred Debits with a credit to Account 131, Cash. The consideration payment was amortized over the life of the new agreement to Account 151, Fuel Stock. The amount amortized to Account 151 was ultimately charged to Account 501, Fuel as coal was burned.

The Commission held that buyout costs should be expended as incurred or, in the event that rate recognition is given in an appropriate proceeding, amortized to expense from a deferred charge account consistent with the rate recognition[18]. Audit staff believe

[18] *Id.*

that the deferral of the one-time payment in Account 186 was appropriate since PacifiCorp was given rate recognition by the state commission. However the amount paid by PacifiCorp to renegotiate the contract does not meet the instruction for the items allowed in Account 151. The Commission has stated that the purpose of Account 151 is to accumulate the cost of fuel on hand, however, since the payment was for contract renegotiation and not directly related to fuel on hand, PacifiCorp should have recorded the amortization to Account 501, instead of Account 151.

*Wyodak Contract*

In May 1987, PacifiCorp and Wyodak Resources Development Corporation entered into a contract under which Wyodak Resources supplied coal to PacifiCorp's coal-fired steam electric generation facility in Wyodak, Wyoming. In 1998, PacifiCorp began to withhold a portion of the invoiced coal price from Wyodak Resources due to contract price disputes. As of March 2001, PacifiCorp had withheld disputed invoice payments for coal delivered by Wyodak Resources. In August 2000, Wyodak Resources filed a lawsuit against PacifiCorp to collect the withheld amounts. PacifiCorp responded with a counter-suit by claiming Wyodak Resources had improperly billed PacifiCorp. In April 2001, Wyodak Resources and PacifiCorp agreed to settle the dispute and renegotiate the Wyodak contract.

As part of the settlement and renegotiation of the Wyodak contract, Wyodak Resources reduced the future unit price of coal, the contract period was extended to December 2022, and PacifiCorp made a one-time payment to Wyodak Resources to settle all past claims (i.e., invoices) under the old coal contract and for the price reduction PacifiCorp received under the terms of the new contract. PacifiCorp did not provide any evidence showing how the settlement amount was determined nor support for the amount actually included in the settlement to relieve past billing disputes.

The one-time payment made to Wyodak Resources by PacifiCorp was recorded by a debit to Account 186, Miscellaneous Deferred Debits, and a credit to Account 131, Cash. The total amount recorded in Account 186, was amortized over the life of the new agreement to Account 151, Fuel Stock. The amount amortized to Account 151 was ultimately charged to Account 501, Fuel, as coal was burned.

Audit staff believe that the one-time payment, excluding payment for the settlement of billing disputes, should have been amortized to Account 501 since PacifiCorp was given rate recognition by the state commission.[19] The portion related to the billing dispute should have been identified immediately expensed to Account 501 unless a regulatory asset had been approved by the state commission to recover the past

[19] *Id.*

disputes. PacifiCorp represented to the state commission that the settlement included past disputes and the contract price renegotiation but it did not identify the components of settlement. The Commission has stated that the purpose of Account 151 is to accumulate the cost of fuel on hand. The amount paid by PacifiCorp to settle and renegotiate the contract did not meet the instructions for and items allowed in Account 151. PacifiCorp should have recorded the amortized costs to Account 501, instead of Account 151. The amount paid by PacifiCorp did not represent costs incurred to acquire coal received and in inventory, nor do such amounts represent payments for the invoiced price of fuel or items of cost listed in Account 151.

PacifiCorp incorrectly recorded coal settlement and renegotiation costs in Account 151, contrary to Commission accounting regulations. PacifiCorp should have recorded these amounts in Account 501. Audit staff verified that that PacifiCorp's incorrect accounting did not impact wholesale formula rates during the audit period.

**Recommendations**

We recommend PacifiCorp:

33. Establish procedures to identify components of coal settlement cost between past coal supply disputes and costs that provide future benefits.

34. Establish procedures to expense immediately prior disputed costs that is related to coal already consumed in Account 501, unless rate recognition is approved by a regulatory authority.

35. Revise accounting procedures to record amortization of deferred coal settlement and renegotiation costs in Account 501.

## 8. Accounting for Liquidated Damages

PacifiCorp incorrectly accounted for amortization of production related regulatory assets associated with liquidated damages as an administrative and general expense in Account 930.2, Miscellaneous General Expense.

### Pertinent Guidance

18 C.F.R. Part 101, Account 930.2, Miscellaneous General Expenses, states in part:

> This account shall include the cost of labor and expenses incurred in connection with the general management of the utility not provided for elsewhere.

Order No. 552, states in part:

> Account 182.3 would include costs incurred and charged to expense which have been, or are soon expected to be authorized for recovery through rates and which are not specifically provided for in other accounts. Regulatory assets would be recorded by charges to Account 182.3 and credits to Account 407.4. Amounts in Account 182.3 would be amortized to Account 407.3 over the appropriate rate recognition period.[20]

18 C.F.R. Part 101, Account 557, Other Expenses, states in part:

> This account shall be charged with any production expenses including expenses incurred directly in connection with the purchase of electricity, which are not specifically provided for in other production expense accounts. Charges to this account shall be supported so that a description of each type of charge will be readily available.

### Background

PacifiCorp subcontracted several production plant related construction projects. Many of the construction projects included liquidated damages due to PacifiCorp because

[20] *Revision to Uniform Systems of Accounts to Account for Allowances under the Clean Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and to Form Nos. 1, 1-F, 2 and 2-A,* Order No. 552, 62 FERC ¶ 61,299 at 85-86 (1993).

the subcontractor missed performance milestones.[21] PacifiCorp collected several liquidated damages as construction invoice credits or direct payments from multiple contractors[22] due to contractual performance breaches on certain capital projects.

*Liquidated damages received and related accounting*

PacifiCorp received liquidated damages of approximately $3.35 million and approximately $6.9 million, for construction delays of the Goodnoe Hills wind project located in Goldendale, Washington, and the Lake Side 1 natural gas generation plant located in Vineyard, Utah, respectively. PacifiCorp also received liquidated damages for contractual breach at its Jim Bridger Unit 4, Naughton Unit 1, and Naughton Unit 2 plants in the amount of approximately $1.6 million. PacifiCorp accounted for the liquidated damages for each project as a credit to construction work-in progress with a corresponding debit to cash or accounts payable. By crediting construction work in progress, PacifiCorp ultimately reduced the total cost of each project that was recorded in the various plant in service accounts to reflect the original cost of the plants. The cost containment benefit of the liquidated damage was passed on to customers in the form of lower depreciation expense over the life of the plants.

*Revaluation of Regulatory Assets*

PacifiCorp filed rate cases[23] in Wyoming and Utah for its Power Cost Adjustment Mechanism and Energy Balancing Account Mechanism from 2008 through 2013. PacifiCorp and its retail customers reached settlement agreements for all years with the approval of state commissions. As part of the settlement agreements, PacifiCorp was required to revalue the existing regulatory assets for the Power Cost Adjustment Mechanism and Energy Balancing Account Mechanism in Account 182.3, Other

[21] These liquidated damages were financial compensations that were agreed upon by the parties during the formation of a contract for PacifiCorp to collect as compensation upon a specific breach of the contract by subcontractor, (e.g., late performance, delay in delivery, etc.).

[22] Those contractors are Northwest wind partners LLC and Lake Side Power, LLC

[23] *See* Wyoming Public Service Commission Docket Nos. 20000-341-EP-09, 20000-315-EP-08, 20000-315-EP-13 for PacifiCorp tariff schedule 94, Power Cost Adjustment Mechanism for 2009, 2008 and 2013 (PCAM); Utah Public Service Commission Docket Nos. 13-035-32, 13-035-T14 for PacifiCorp's tariff Schedule 94, Energy Balancing Account Mechanism.

Regulatory Assets, by revising the amortization period for the regulatory assets with the life of the plants[24] that were credited with the liquidated damages.

*Accounting for Regulatory Asset changes and amortizations*

Based on state rate case settlements, PacifiCorp reclassified regulatory assets included in a sub-account of Account 182.3 to another sub-account of Account 182.3. PacifiCorp amortized the revalued regulatory assets by debiting Account 930.2, Miscellaneous General Expenses. PacifiCorp excluded the amortizations recorded in Account 930.2 when developing the wholesale transmission revenue requirements.

Audit staff point out that, Account 930.2 is used to record expenses incurred in connection with the general management of the utility not provided for elsewhere in the Commission accounting regulations. Since the amortized regulatory assets were production related, PacifiCorp should have recorded the amortization of the regulatory assets in the specific productions operating and maintenance account instead of in Account 930.2.

**Recommendations**

We recommend PacifiCorp:

36. Revise accounting procedures to record regulatory asset amortization related to production plant liquidated damages in the functional operating and maintenance accounts when appropriate.

37. Record correcting entries to reclassify regulatory asset amortization related to state created advance refund of liquidated damages from Account 930.2 to Account 557, Other Expenses.

[24] Goodnoe Hill, Lake Side, Jim Bridger, and Naughton Unit 1 and 2

**9. Accounting for Pensions, PBOP and Other Benefits**

PacifiCorp recorded the cost of pensions, post-retirement benefits other than pensions (PBOP) and other employee benefits in various functional operating and maintenance expense accounts, instead of in Account 926, Employee Pensions and Benefits.

**Pertinent Guidance**

18 C.F.R. Part 101, Account 926, Employee Pensions and Benefits, states in part:

> A. This account shall include pensions paid to or on behalf of retired employees, or accruals to provide for pensions, or payments for the purchase of annuities for this purpose, when the utility has definitely, by contract, committed itself to a pension plan under which the pension funds are irrevocably devoted to pension purposes, and payments for employee accident, sickness, hospital, and death benefits, or insurance thereof. This also includes expenses incurred in medical, educational or recreational activities for the benefit of employees, and administrative expenses in connection with employee pensions and benefits.

**Background**

PacifiCorp recorded pension, PBOP and other benefits (e.g., medical, vision, 401K, etc.) to employees' primary functional account "i.e. production, transmission and distribution etc." The amounts recorded in employee functional accounts are redistributed using a fully loaded labor rate,[25] based on the activity performed by the employee "i.e. capital projects, O&M, A&G etc." PacifiCorp did not record pensions, PBOP and other benefits expenses in Account 926, Employee Pensions and Benefits, as required by the Commission accounting regulations. The Commission accounting regulations require a company to record these costs in Account 926, except for amounts property assignable to construction or non-utility operating accounts. Although PacifiCorp functionalized pension, PBOP and other employee benefits in O&M accounts, the total amounts that should have been recorded in Account 926 was noted on the FERC Form No. 1.

[25] PacifiCorp's fully loaded labor rate included employee base pay, benefits and taxes, direct supervision, overhead etc.

In order to meet the uniformity of accounting transactions across utilities under the Commission's jurisdiction, audit staff believe PacifiCorp should have recorded pensions, PBOP and other employee benefits in Account 926 or sought Commission approval before it deviated from Commission accounting regulation.

**Recommendation**

We recommend PacifiCorp:

38. Revise procedures to ensure it records pensions, PBOP, and other employee benefits in Account 926, Employee Pensions and Benefits, as required by the Commission accounting regulations.

# Appendix: PacifiCorp's Comments on Audit Report

PACIFICORP

Pacific Power |
Rocky Mountain Power
825 NE Multnomah, Suite 1800
Portland, Oregon 97232

***Via Electronic Delivery***
***Followed by Overnight Courier***

August 22, 2017

Mr. Bryan K. Craig
Director and Chief Accountant
Division of Audits and Accounting
Office of Enforcement
Federal Energy Regulatory Commission
888 First street NE, Room 5K-13
Washington, DC 20426

RE: PacifiCorp
Docket No. FA16-4-000
Response to August 15, 2017 Draft Audit Report

Dear Mr. Craig:

In accordance with Part 41 of the regulations of the Federal Energy Regulatory Commission (FERC or the Commission), please accept on behalf of PacifiCorp this response to your August 15, 2017 letter transmitting the draft audit report in the above-captioned docket (Draft Audit Report).

PacifiCorp accepts Division of Audit and Accounting's (DAA) proposed findings and recommendations in the Draft Audit Report and proposes the corrective actions below.

## I. Responses to DAA's Findings and Recommendations

### A. Storm Damage Accounting and Costs Recovery

Summary of Proposed Finding & Recommendations

Audit staff concludes PacifiCorp improperly overbilled storm damage costs to its merchant function and third-party wholesale customers that procured transmission services under PacifiCorp's OATT and did not make refunds to its wholesale customers for the excessive storm damage revenues collected from its wholesale customers.

1. *Refrain from recovering actual and estimated storm damage costs from wholesale customers associated with the same storm. Revise policies, procedures and practices to ensure the proper accounting procedures are employed to prevent the double collection of storm damage costs through the wholesale formula rates.*
2. *Revise wholesale formula rates development procedures to strengthen coordination between accounting and wholesale formula rates development departments.*
3. *Provide training to staff on the revised storm damage accounting and rate development methods. Also, develop a training program that supports the provision of periodic training in this area, as needed.*
4. *Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate storm damage recoveries since 2012, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to be refunded; and (5) period(s) refunds will be made. Include the results of the analysis of transmission-related storm damage expenses in the refund amount.*
5. *File a refund report with the Commission after receiving DAA's assessment of the refund analysis.*
6. *Refund amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of Commission regulations.*

PacifiCorp Response

PacifiCorp accepts the finding and the recommendations.

PacifiCorp's Corrective Action Plan

1. PacifiCorp will revise its policies, procedures and practices to ensure the proper accounting procedures are used to prevent the double collection of storm damage costs through the wholesale formula rates and has strengthened coordination between the accounting department and the department responsible for developing wholesale formula rates. PacifiCorp will further revise its policies, procedures and practices to include training for staff on the revised accounting and rate-development methods.
2. PacifiCorp will submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate storm damage recoveries since 2012, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to be refunded; and (5) period(s) refunds will be made. PacifiCorp will include the results of the analysis of transmission-related storm damage expenses in the refund amount.
3. PacifiCorp will file a refund report with the Commission after receiving DAA's assessment of the refund analysis and will refund amounts disclosed in the refund report to wholesale customers, with interest.

**B. Mining Assets**

Summary of Proposed Finding and Recommendations

Audit staff concludes PacifiCorp inappropriately recovered from its wholesale customers the cost of production-related mining assets through its wholesale formula rates. Audit staff claims this resulted in PacifiCorp overstating its wholesale transmission revenue requirement by approximately $3.7 million, which led to overbilling third-party wholesale customers by approximately $600,000.

7. *Revise procedures for computing the annual wholesale transmission revenue requirement and billing to wholesale customers by ensuring that it excludes cost of mining assets from the wholesale formula rates.*
8. *Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate cost of mining asset recoveries that resulted from the inclusion of mining assets in the wholesale formula rates base since 2012, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to be refunded; and (5) period(s) refunds will be made.*
9. *File a refund report with the Commission after receiving DAA's assessment of the refund analysis.*
10. *Refund amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of Commission regulations.*

PacifiCorp Response

PacifiCorp accepts this finding and the recommendations.

PacifiCorp's Corrective Action Plan

4. PacifiCorp has divested from all of its directly owned mining assets, except minor amounts of land, as of year-end 2015. PacifiCorp will revise procedures for computing the annual wholesale transmission revenue requirement and billing to wholesale customers by ensuring that it excludes any remaining cost of mining assets from the wholesale formula rates.
5. PacifiCorp will submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate cost of mining asset recoveries that resulted from the inclusion of mining assets in the wholesale formula rates base since 2012, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to be refunded; and (5) period(s) refunds will be made.
6. PacifiCorp will file a refund report with the Commission after receiving DAA's assessment of the refund analysis and will refund amounts disclosed in the refund report to wholesale customers, with interest.

## C. Amortization of Regulatory Assets

Summary of Proposed Finding and Recommendations

Audit staff concludes PacifiCorp inappropriately included amortization of regulatory assets in its wholesale formula rates. Audit staff claims this resulted in PacifiCorp overstating its wholesale transmission revenue requirement by approximately $800,000, which led to overbilling third-party wholesale customers by approximately $100,000.

11. *Revise accounting procedures to record pensions, and postretirement regulatory asset amortizations in Account 926.*
12. *Revise accounting procedures to exclude amortization of environmental damages regulatory assets to Account 925, and record amortization of amounts recovered in retail rates in appropriate functional operating and maintenance accounts.*
13. *Provide training to staff on the revised regulatory assets accounting and rate development methods. Also, develop a training program that supports the provision of periodic training in this area, as needed.*
14. *Record correcting entries to reclassify pensions, and postretirement regulatory assets amortization from Account 920 to Account 926.*
15. *Record correcting entries to reclassify environmental damages amortization from Account 925 and record the amounts recovered from retail rates in appropriate functional operating and maintenance accounts.*
16. *Revise procedures for computing wholesale formula rates billings to wholesale customers to exclude amortization of regulatory assets which were not approved by the Commission.*
17. *Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate regulatory asset amortizations which were included in wholesale formula rates and the refunds resulting from the inclusion of those regulatory asset amortizations in the wholesale formula rates, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to be refunded; and (5) period(s) refunds will be made.*
18. *File a refund report with the Commission after receiving DAA's assessment of the refund analysis.*
19. *Refund amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of Commission regulations.*

PacifiCorp Response

PacifiCorp accepts this finding and the recommendations.

PacifiCorp's Corrective Action Plan

7. PacifiCorp will revise accounting procedures to: record pensions and post-retirement regulatory asset amortizations in Account 926; exclude amortization of environmental damages regulatory assets to Account 925; and record amortization of amounts recovered in retail rates in appropriate functional operating and maintenance accounts. PacifiCorp's revised procedures will include provisions on training.
8. PacifiCorp will record correcting entries in 2017 to: reclassify pensions and post-retirement regulatory assets amortization from Account 920 to Account 926; and reclassify environmental damages amortization amounts recovered in retail rates from Account 925 to the appropriate functional operating and maintenance accounts.
9. PacifiCorp will revise procedures for computing wholesale formula rates billings to wholesale customers to exclude amortization of regulatory assets that were not approved by the Commission.
10. PacifiCorp will submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate regulatory asset amortizations which were included in wholesale formula rates and the refunds resulting from the inclusion of those regulatory asset amortizations in the wholesale formula rates, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to be refunded; and (5) period(s) refunds will be made.
11. PacifiCorp will file a refund report with the Commission after receiving DAA's assessment of the refund analysis and will refund amounts disclosed in the refund report to wholesale customers, with interest.

## D. Injuries and Damages Accounting and Costs Recovery

Summary of Proposed Finding and Recommendations

Audit staff concludes PacifiCorp inappropriately accounted for and recovered injuries and damages through its wholesale formula rates when it had insurance policies to cover the cost of those damages. Audit staff claims this resulted in PacifiCorp overstating wholesale transmission revenue requirement by approximately $2.9 million, which led to overbilling third-party wholesale customers by approximately $400,000.

*20. Revise policies, procedures and practices to book accruals for covered damage amounts in Account 426.5 when management makes a decision not to seek insurance recoveries for damages covered by insurance.*

*21. Provide training to staff on the revised injuries and damages expenses covered by insurance accounting and rate development methods. Also, develop a training program that supports the provision of periodic training in this area, as needed.*

*22. Submit a refund analysis within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate injuries and damages recoveries that resulted from the inclusion of excessive estimated expenses in the wholesale formula rates since 2012, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to be refunded; and (5) period(s) refunds will be made.*

*23. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.*

*24. Refund amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of Commission regulations.*

PacifiCorp Response

PacifiCorp accepts this finding and the recommendations.

PacifiCorp's Corrective Action Plan

12. PacifiCorp will revise its policies, procedures and practices to book accruals for covered damage amounts in Account 426.5 when the Company determines it will not seek insurance recoveries for damages covered by insurance. The revised policies, procedures and practices will include provisions for training.
13. PacifiCorp will submit a refund analysis within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate injuries and damages recoveries that resulted from the inclusion of excessive estimated expenses in the wholesale formula rates since 2012, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to be refunded; and (5) period(s) refunds will be made.
14. PacifiCorp will file a refund report with the Commission after receiving DAA's assessment of the refund analysis and will refund amounts disclosed in the refund report to wholesale customers, with interest.

**E. Allowance for Funds Used During Construction**

Summary of Proposed Finding and Recommendation

Audit staff concludes PacifiCorp's methods for calculating the rate for Allowance for Funds Used During Construction (AFUDC) was deficient because PacifiCorp inappropriately: included letter-of-credit fees (up-front and quarterly) as part of short-term debt-interest expense to compute the AFUDC rate; included Unappropriated Undistributed Subsidiary Earnings as part of the equity component for the purpose of computing the AFUDC rate; and included Accumulated Other Comprehensive Income (AOCI) as part of the equity

component for the purpose of computing the AFUDC rate in 2013. Audit staff asserts that because of this, PacifiCorp over-accrued Allowance for Funds Used During Construction by approximately $6.8 million for 2013 through 2015. Audit staff claimed that this resulted in PacifiCorp overbilling wholesale customers for AFUDC costs included in utility plant that was included in wholesale formula rate determinations through rate base and depreciation charges.

25. *Revise its procedures to ensure its AFUDC rate calculation is consistent with Order No. 561 and other applicable Commission requirements.*
26. *Revise its procedures to ensure that Account 216.1 is excluded from equity components used to derive AFUDC rate.*
27. *Revise its procedures to ensure that the amounts reported on the FERC Form No. 1 are used to compute AFUDC rate.*
28. *Provide training to staff on the revised AFUDC accounting and rate calculation method. Also, develop a training program that supports the provision of periodic training in this area, as needed.*
29. *Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds to wholesale customers base since 2012, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to be refunded; and (5) period(s) refunds will be made.*
30. *File a refund report with the Commission after receiving DAA's assessment of the refund analysis.*
31. *Refund amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of Commission regulations.*

PacifiCorp Response

PacifiCorp accepts this finding and the recommendations.

PacifiCorp's Corrective Action Plan

15. PacifiCorp revised its procedures to: ensure its AFUDC rate calculation is consistent with Order No. 561 and other applicable Commission requirements; ensure that Account 216.1 is excluded from equity components used to derive the AFUDC rate; and ensure that the amounts reported on the FERC Form No. 1 are used to compute the AFUDC rate. PacifiCorp's revised procedures will include provisions for training. PacifiCorp intends to petition the Commission to obtain written authorization to include: (1) Commitment fees in the short-term debt-rate component of the AFUDC rate calculation and (2) Unappropriated Undistributed Subsidiary Earnings of wholly owned captive mining companies (Account 216.1) in the common equity component of the AFUDC rate calculation.
16. PacifiCorp will submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of

refunds to wholesale customers base since 2012, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to be refunded; and (5) period(s) refunds will be made.

17. PacifiCorp will file a refund report with the Commission after receiving DAA's assessment of the refund analysis and will refund amounts disclosed in the refund report to wholesale customers, with interest.

## F. Asset Retirement Obligations

Summary of Proposed Finding and Recommendation

Audit staff concludes PacifiCorp's accounting and rate treatment of Asset Retirement Obligations (ARO) were deficient because PacifiCorp inappropriately: excluded accumulated depreciation amounts removed from Account 108, Accumulated Provision for Depreciation of Electric Utility Plant, to implement ARO accounting in the wholesale formula rates determinations, resulting in an understatement of its wholesale transmission revenue requirement which led to under-billings to its wholesale customers through its wholesale formula rates; and included estimated future asset retirement costs recorded in General Plant in its wholesale formula rate base, resulting in an overstatement of its wholesale transmission revenue requirement, which led to overbillings to its wholesale customers. Audit staff claims that as a result of the deficiencies, PacifiCorp under-billed its wholesale customers through its wholesale formula rates.

*32. Revise existing accounting and rate development procedures and practices to ensure all ARO-related accounting effects and associated adjustments are excluded from wholesale formula rates determinations.*

PacifiCorp Response

PacifiCorp accepts this finding and the recommendation.

PacifiCorp's Corrective Action Plan

18. PacifiCorp will revise existing accounting and rate development procedures and practices to ensure all ARO-related accounting effects and associated adjustments are excluded from wholesale formula rates determinations.

## G. Accounting for Coal Settlement Costs

Summary of Proposed Finding and Recommendations

Audit staff concludes PacifiCorp incorrectly accounted for amortization of two coal settlement payments in Account 151, Fuel Stock, instead of Account 501, Fuel.

*33. Establish procedures to identify components of coal settlement cost between past coal supply disputes and costs that provide future benefits.*

*34. Establish procedures to expense immediately prior disputed costs that is related to coal already consumed in Account 501, unless rate recognition is approved by a regulatory authority.*

*35. Revise accounting procedures to record amortization of deferred coal settlement and renegotiation costs in Account 501.*

PacifiCorp Response

PacifiCorp accepts this finding and the recommendations.

PacifiCorp's Corrective Action Plan

19. PacifiCorp will establish procedures to identify components of coal settlement cost between past coal supply disputes and costs that provide future benefits.
20. PacifiCorp will establish procedures to immediately expense prior-disputed costs that are related to coal already consumed in Account 501, unless rate recognition is approved by a regulatory authority
21. PacifiCorp will revise accounting procedures to record amortization of deferred coal settlement and renegotiation costs in Account 501.

**H. Accounting for Liquidated Damages**

Summary of Proposed Finding and Recommendations

Audit staff concludes PacifiCorp incorrectly accounted for amortization of production-related regulatory assets associated with liquidated damages as an administrative and general expense in Account 930.2, Miscellaneous General Expense.

*36. Revise accounting procedures to record regulatory asset amortization related to production plant liquidated damages in the functional operating and maintenance accounts when appropriate.*

*37. Record correcting entries to reclassify regulatory asset amortization related to state created advance refund of liquidated damages from Account 930.2 to Account 557, Other Expenses.*

PacifiCorp Response

PacifiCorp accepts this finding and the recommendations.

PacifiCorp's Corrective Action Plan

22. PacifiCorp will revise accounting procedures to record regulatory asset amortization related to production-plant liquidated damages in the functional operating and maintenance accounts when appropriate.

23. PacifiCorp recorded correcting entries in 2017 to reclassify current regulatory asset amortization related to production-plant liquidated damages from Account 930.2 to Account 557.

## I. Accounting for Pensions, PBOP and Other Benefits

Summary of Proposed Finding and Recommendations

Audit staff concludes PacifiCorp recorded the cost of pensions, post-retirement benefits other than pensions (PBOP) and other employee benefits in various functional operating and maintenance expense accounts, instead of in Account 926, Employee Pensions and Benefits.

*38. Revise procedures to ensure it records pensions, PBOP, and other employee benefits in Account 926, Employee Pensions and Benefits, as required by the Commission accounting regulations.*

PacifiCorp Response

PacifiCorp accepts this finding and the recommendation, and proposes a corrective action plan that avoids the need to substantially revise PacifiCorp's accounting systems.

PacifiCorp's accounting for pensions, PBOP and other benefits was an issue in PacifiCorp's last audit.[1] The Office of the Chief Accountant, however, deferred the issue because it planned "to study the issue of assignment of payroll taxes, pensions, and [PBOP] on an industry-wide basis, and therefore did not make any recommendations on the subject pending completion of the study and any resulting FERC action."[2] The Draft Audit Report provides final clarification on this issue.

PacifiCorp, however, built its accounting systems around its practice of functionalizing these costs to accurately account for both costs that are situs-assigned to one of PacifiCorp's six state jurisdictions and transmission-function costs. PacifiCorp anticipates that it could take 12-24 months to revise its accounting processes and software to incorporate manual allocation processes. PacifiCorp believes it can address this concern by revising its procedures to charge the full cost of pensions, PBOP and other benefits to Account 926 with an offsetting credit to Account 929, Duplicate Charges – Credit, thereby maintaining the benefits of functionalization, ensuring zero impact to the formula rate, and appropriately populating Account 926 in the FERC Form No 1 with pension, PBOP and other benefit costs.

PacifiCorp's Corrective Action Plan

24. PacifiCorp revised its procedures effective with the second quarter 2017 Form 3Q filed in August 2017 to charge the full cost of pensions, PBOP and other benefits to Account 926, and book an offsetting credit to Account 929 to ensure zero impact to the formula rate.

[1] FERC Docket No. FA96-34-000 and FA94-34-001.
[2] Draft Audit Report in FA94-34-000 and FA94-34-001 at p. 30-31.

This revised procedure will also appropriately populate Account 926 in PacifiCorp's 2017 FERC Form No. 1 with pension, PBOP and other benefit costs.

## II. Conclusion

PacifiCorp thanks the audit staff for their professionalism throughout the course of the audit. The company appreciates the opportunities provided by audit staff to discuss and seek clarifications on the findings and recommendations. Audit staff's willingness to discuss its findings and recommendations removed a number of PacifiCorp's initial concerns.

Please contact the undersigned with any questions.

Respectfully submitted,

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Document Content(s)

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Docket No. UE 433
Exhibit PAC/3400
Witness: Anna DeMers

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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# Reply Testimony of Anna DeMers

**July 2024**

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**Q. Are you the same Anna DeMers that previously provided direct testimony in this case on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?**

A. Yes.

## I. PURPOSE AND SUMMARY

**Q. Please summarize the proposals supported in your opening testimony.**

A. The primary purpose of my opening testimony was to introduce the Capacity Reservation Charge and the Excess Demand Charge. I also presented additional recommendations on behalf of the Company including a proposal to extend the period during which large customers are eligible for Line Extension Refunds, a proposal to change the Company's definition of Extension Limits, and a proposal to change the timing when Line Extension Advances are paid by large customers

**Q. What is the purpose of your reply testimony?**

A. My reply testimony responds to the testimonies of Staff of the Public Utility Commission of Oregon (Commission) (Staff) witness Curtis Dlouhy, Oregon Citizens' Utility Board (CUB) witness John Garrett, Alliance of Western Energy Users (AWEC) witness Lance Kaufman, Data Center Coalition (DCC) witness Collin Cain, and Vitesse, LLC (Vitesse) witness Kyra Coyle, as the testimony of these parties relates to my opening testimony.

**Q. Do any other Company witnesses also respond to parties on the items addressed in your opening testimony?**

A. Yes. Company witness Robert M. Meredith discusses the Company's proposed treatment of any revenue from the Capacity Reservation Charge and Excess Demand Charge in his reply testimony.

## II. UPDATED EXHIBITS

**Q. Have you prepared any updates to the exhibit filed with your reply testimony?**

A. No. The Company's dollar-per-kilowatt Capacity Reservation Charge and Excess Demand Charge recommendations have not changed. No update to Exhibit PAC/1801 is being filed at this time.

## III. RESPONSE TO PARTIES' OPENING TESTIMONY

**Q. How have you organized your response to parties' opening testimony?**

A. My responses to parties are organized by topic. My reply testimony first addresses issues regarding the Capacity Reservation Charge and Excess Demand Charge, and then addresses testimony from parties pertaining to other proposed tariff changes presented in my opening testimony.

**Q. Should your silence on any arguments presented by other parties on topics addressed in your opening testimony be interpreted as support for the positions of other parties?**

A. No. My silence on any of the parties' testimony should not be interpreted as support or agreement.

## IV. URGENCY

**Q. Have any witnesses to this proceeding commented on the urgency of instituting some measure to recover the cost of Reserved Capacity?**

A. Yes. DCC, Vitesse, and AWEC made statements questioning the urgency of changing the Company's policies surrounding Reserved Capacity. For example, DCC stated that, "PacifiCorp has not demonstrated that there is imminent impact to its system from very large customers that warrants new and novel tariff rates and provisions,"

and pointed out that the Company has not identified specific investments it is currently making to serve very large customers.[1] Similarly, Vitesse characterized the Company's proposal as being, "in search of a problem which does not currently exist," with the cost shifting the Company is anticipating being a future and not necessarily a current problem.[2] AWEC proposed that determination of the appropriate charge amount, beyond an indicative charge, be put off for now, with part of the justification for this action being that the Company has been unwilling to provide data supporting the urgency of this matter and demonstrating appropriate charge levels.[3]

On the other hand, Staff expressed concern over the potential for very large customers to impact the Company's ability to serve its load, interconnect new load, and the risk of stranded asset creation driven by service requests from very large customers when arguing that it is in the best interest of customers to institute some form of a Capacity Reservation Charge, at least at a high level.[4] CUB also argued that the outsized impact that a few very large customers could create for hundreds of thousands of smaller customers is impetus to reexamine the Company's policies.[5]

**Q. Has the Company been unwilling to provide information to demonstrate the imminent costs of Excess Reserved Capacity, as stated by AWEC?**

A. No. The Company was unable to answer every question asked in discovery because the requested information is either unavailable, or the Company could not provide this information without revealing customer-specific information.

[1] DCC/100, Cain/3.
[2] Vitesse/100, Coyle/13.
[3] AWEC/200, Kaufman/043.
[4] Staff/700, Dlouhy/3-4.
[5] CUB/300, Garrett/4.

The Company plans necessary large generation and transmission facility investments by analyzing its facilities as an integrated system. Most large generation and transmission facilities are not currently built with a single customer in mind, and so the Company cannot identify an exact dollar amount for all costs of facilities built or triggered specifically to serve additional large customer load. Accurately determining which facilities might not be built in the future or would not have been built in the past if more accurate load forecasts were provided to the Company is an even bigger challenge, and any list of such investments provided by the Company would likely be incomplete. The difficulty of performing this analysis will not change with the passage of time, and so deferring discussions on the cost of Reserved Capacity to a later date will not increase the availability of this data.

Additionally, while there are currently several existing customer sites and pending large load requests in Oregon with total load requirements greater than 25 megawatts (MW), the number of owners of these sites is actually very small due to very large customers in Oregon having more than one or multiple planned or existing project sites. At present, the majority of existing sites and pending requests of this size in Oregon belong to two business entities. It would be simple for customers to deduce customer-specific information if provided aggregate data on very large customers in Oregon due to the small number of owners of project sites. Therefore, the Company has withheld some data to protect customer-specific information.

**Q. Have parties pointed to specific data to contradict the Company's position that very large load requests will have a considerable impact on the Company's system in the near-term?**

A. Yes. For example, as mentioned by DCC, the Company has only received 12 requests in Oregon over the last few years which are greater than 25 MW.[6] However, this information does not fully demonstrate the potential magnitude impact of these requests on the Company's system or on Oregon customers as many of the requests the Company has received from individual customers in recent years are for hundreds of MW for single project sites.

**Q. Is there any available information you can provide to demonstrate the magnitude of very large load requests to demonstrate the impact this emerging customer class is creating and will create on the Company's system?**

A. Yes. While the Company is not willing to separately provide load information on large customers in Oregon, providing this information in aggregate for the Company's six-state system eliminates the Company's concerns regarding the potential of customer-specific data being derivable from information provided by the Company.

Between 2020 and 2023, the Company received requests and signed agreements[7] with very large customers for approximately 13 gigawatts (GW) of new load in its six-state service territory. For reference, the Company's system coincident peak in 2023 was about 10 GW. As the Company has continually stated, very large

[6] DCC/100, Cain/10-11.
[7] These do not all reflect full Line Extension Agreements, but may include agreements for the Company to study the applicant's load request and/or procure long-lead time equipment in advance of a future energization date. The presence of signed agreements indicates that these are serious requests.

customers will be a significant driver of system costs and system design in coming years.

**Q. Are other utilities across the nation facing similar pressures?**

A. Yes. Numerous news headlines have documented the dramatic level of new load requests utilities have been receiving in recent years.[8] Additionally, the chart below from the Electric Power Research Institute indicates the significant impact that the growth in artificial intelligence and data center energy consumption could have on the state of Oregon, specifically.[9]

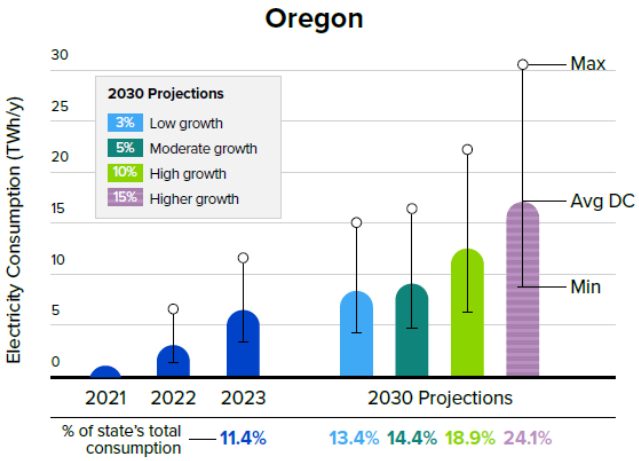


*Figure A11.*
*Projected electricity consumption in Oregon data centers*

[8] *See* Ethan Howland, *AEP faces 15 GW of new load, driven by Amazon, Google, other data centers: interim CEO Fowke*, UTILITY DIVE (May 2, 2024) *available at* https://www.utilitydive.com/news/aep-data-centers-amazon-google-load-growth-epa/714806/; Brian Martucci, *Data center, AI load growth could threaten grid reliability: Conference Board*, UTILITY DIVE (Jun. 20, 2024) *available at* https://www.utilitydive.com/news/data-center-ai-load-growth-grid-reliability-conference-board/719380/.

[9] *Powering Intelligence, Analyzing Artificial Intelligence and Data Center Energy Consumption*, ELECTRIC POWER RESEARCH INSTITUTE at 24 (May 28, 2024) (*available at* https://www.epri.com/research/products/000000003002028905).

**Q. Please comment on why it is essential to institute measures to manage Excess Reserved Capacity as soon as possible.**

A. The Company is being approached and signing agreements with more and more very large customers each year. In addition to more accurately allocating costs to very large customers to ensure they are paying their cost of service, the Company believes that the institution of a Capacity Reservation Charge and Excess Demand Charge will incentivize new customers to forecast load more accurately and will encourage relinquishment of unused capacity by existing customers. Instituting policies to manage Excess Reserved Capacity before the Company makes investments to serve new loads for very large customers will produce the maximum benefit by preventing unnecessary overbuilding. It is also important to provide transparency to customers as soon as possible about what charges related to Reserved Capacity will be implemented so that they can make informed business decisions, particularly in industries that are currently undergoing rapid growth and evolution.

**Q. Because the Company believes changing its management of Reserved Capacity is an urgent matter, has the Company proposed similar charges in other jurisdictions?**

A. Vitesse pointed out that the Company does not have approved Capacity Reservation Charges or Excess Demand Charges in other jurisdictions.[10] These proposals are new, and the Company filed an application to institute these charges in Oregon first. The Company has since made a similar filing in Utah and will do so shortly in Wyoming. The Company plans to file a similar application in Washington, also. Tariff

[10] Vitesse/100, Coyle/11-12.

provisions in Idaho require customers requesting more than 30 MW to take service under special contracts, so the Company can propose special contract provisions to capture the cost of Reserved Capacity for all Idaho customers requiring more than 30 MW under the existing tariff. The Company does not currently have requests from very large customers in California and therefore does not have immediate plans to file a similar application in that state.

## V. STAKEHOLDER INPUT AND FORUM

**Q. Please comment on DCC and Vitesse's mention of the Company's lack of collaboration with very large customers in designing the Capacity Reservation Charge and Excess Demand Charge, and the argument that the Company did not receive appropriate stakeholder input prior to making these proposals.[11]**

A. The Company disagrees that very large customers are the only stakeholders in this matter. It's true that the Capacity Reservation Charge and Excess Demand Charge, as proposed by the Company, are designed to be charged primarily to very large customers and these customers will be immediately affected if the Commission approves the Company's recommendations. However, the Company's management of very large load requests and Reserved Capacity, especially policies with the potential to reduce or reallocate the costs of transmission and generation investments going forward, will affect all customers over time. Collaborating exclusively with very large customers on this issue would therefore leave out key impacted parties.

Under the existing tariffs, all customers bear the responsibility of paying for system investments based on actual energy usage. The cost of investments made

[11] Vitesse/100, Coyle/20,21 and DCC/100, Cain/34.

based on load forecasts is borne by customers in proportion to the actual load and energy usage of their class, no matter how their class may have influenced load forecasts that triggered system upgrades. If the Company does not design the Capacity Reservation Charge and Excess Demand Charge appropriately, costs that should have been borne by very large customers may be shifted and absorbed by other customer classes and vice versa. As CUB pointed out, "(t)he uncertainties regarding the longevity and load forecasts of very large customers are highly consequential to utility planning, investing, and intra-class cost allocation."[12]

**Q. Is a general rate case proceeding the best forum in which to handle questions regarding the Company's proposals related to Reserved Capacity?**

A. Yes. General rate case proceedings involve engagement of varied stakeholder groups in robust, thorough, and public proceedings. This is the best forum for deciding issues, like the Company's proposals to manage Reserved Capacity, which affect all customers.

## VI. RESERVED CAPACITY ACCURACY

**Q. Please explain how the Company incorporates the service requirements for very large customers into its system investment planning decisions.**

A. The Company's load forecasts are used to plan transmission and generation investments. The Company includes specific load projections in its forecasts for a small number of very large customers, and uses historical data and other generalized information about customers in each class to forecast load for the remaining customers.

[12] CUB/300, Garrett/4.

**Q. Why does the Company forecast load individually for only a few very large customers?**

A. Variations in the energy usage of just a few very large customers have outsized impacts on the Company's system. As Staff explained, "a particular very large customer creates costs that are more easily assigned to the customer and present significant stranded asset risk."[13]

In addition to their large per-customer impact on Company investments, very large customers are sophisticated energy users with unique requirements. Using generalized assumptions to forecast how very large customers will operate their businesses is inappropriate. This is increasingly true for modern industries, and most of the very large load requests the Company is receiving are for new and evolving technologies with the majority of new requests coming from data centers. CUB pointed to the mobility and unpredictability of computing industry operations to demonstrate why very large customers present increasing risks to PacifiCorp's system.[14] Indeed, the Company has observed that load projections provided from very large customers at the time service is requested often greatly overestimate actual load requirements. For many large customers, only about 20 percent of the requested load materializes in the first one to three years of service. On the other hand, the primary factors that drive the energy usage of other customer classes, such as weather, do not typically vary by more than a few percent.

[13] Staff/700, Dlouhy/4.
[14] CUB/300, Garrett/4.

**Q. What have parties said about the ability of very large customers to provide accurate forecasts?**

A. Several parties disagree that providing accurate load forecasts is ultimately the responsibility of customers. DCC referred to load forecasting as a responsibility of the Company, and stated that the Company's proposal would, "impose on its large customers forecasting obligations and planning risk traditionally assumed by the Company."[15] AWEC similarly places the burden on PacifiCorp to create accurate forecasts to avoid revenue shortfalls.[16] Other witnesses did not dispute the role of very large customers in providing accurate load forecasts but argued that requiring perfect accuracy from customer forecasts is unreasonable. For example, Vitesse called requiring very large customers to be more accurate than other customers in providing forecasts, "discriminatory treatment."[17] To provide more flexibility in load forecasting requirements, several witnesses proposed alternatives to applying Capacity Reservation charges and Excess Demand Charges to all load underage and overage. CUB, by contrast, called holding very large customers directly accountable for their load forecasts fair because these forecasts directly drive expenses.[18]

**Q. Are the Company's proposals which require accurate load forecasts from large customers discriminatory?**

A. No. The existing Line Extension Tariff includes unique provisions differentiated by customer class, customer load size, and other unique customer characteristics. Some sections of the Company's existing tariff even call out unique treatment for specific,

[15] DCC/100, Cain/12.
[16] AWEC/200, Kaufman/040.
[17] Vitesse/100, Coyle/25.
[18] CUB/300, Garrett/11.

listed industries.[19] Assessing the impact and potential risk which customers present to the Company's system is a standard part of logical cost-based ratemaking. While I am not an attorney, my understanding is that Oregon law acknowledges this concept where it is specifically noted that an "optional schedule or tariff for the provision of energy service that takes into account a customer's past energy usage and provides price incentives designed to encourage changes in the customer's energy usage that correspond to changes in the cost of providing energy" is not discriminatory.[20]

**Q. Please provide the recommendations made by other parties to allow customers more flexibility in providing accurate forecasts.**

A. Vitesse recommended a 60 percent load factor be applied to the aggregate load of all customer sites to assess Excess Reserved Capacity based on system averages.[21] Additionally, Vitesse recommended that customers be allowed an overage of 13 percent before being charged an Excess Demand Charge, based on the Company's planning reserve margin, also applied to aggregated loads.[22] AWEC made a similar recommendation and advocated for the use of a 59 percent load factor before the Capacity Reservation Charge applies, and a 27 percent load overage allowance before the Excess Demand Charge is applied, with both recommendations based on variations in demand at substations serving smaller customers.[23] Staff recommended the Capacity Reservation Charge should only be applied to Excess Reserved Capacity in excess of 2 MW.[24]

[19] Oregon Rule 1, "Service of Questionable Permanency".
[20] ORS 757.310 (c).
[21] Vitesse/100, Coyle/27, 31.
[22] Vitesse/100, Coyle/34-37.
[23] AWEC/200, Kaufman/44.
[24] Staff/700, Dlouhy/5.

**Q. Does the Company agree that very large customers should be provided some flexibility to provide less than perfect load forecasts?**

A. Yes, the Company agrees that providing some flexibility to very large customers to allow for limited overestimation of Reserved Capacity is not unreasonable. The Company's original proposed calculation of the Capacity Reservation charge uses a historic lookback at a customer's peak demand over either a 12-month or 36-month period, which already provides monthly flexibility for seasonal variations in load. However, the Company is amenable to additionally applying a buffer to the calculation of Excess Reserved Capacity equal to a percentage of load. The Company does not agree that allowing customers any buffer to exceed their load forecasts without incurring an Excess Demand Charge is reasonable because of the risk of reliability concerns and other negative outcomes that this presents to the Company's system. If customers need to err towards underestimation or overestimation of load requirements, it is preferable for customers to slightly overestimate their needed load.

**Q. What buffer is the Company proposing to include in the calculation of Excess Reserved Capacity?**

A. The Company is proposing a five percent buffer. This amount is only slightly larger than Staff's recommendation for customers requiring approximately 60 MW, used in Staff's analysis, but would scale proportionately with larger customers.[25]

[25] Staff/700, Dlouhy/5-6.

## VII. APPROPRIATENESS OF CAPACITY RESERVATION CHARGE DESIGN

**Q. Please summarize DCC's testimony regarding the Company's calculation of the Capacity Reservation Charge.**

A. DCC lists a number of concerns and criticisms of the Company's calculation which includes the following:

- DCC asserts that the Company did not adequately justify why 11.5 percent of fixed generation costs should be assigned to the Capacity Reservation Charge.
- DCC alleges that the calculation is not cost justified because it believes the Company did not demonstrate that the values it calculated would be caused by a customer's actual demand falling short of its Reserved Capacity.
- The calculation excludes non-FERC transmission costs.
- DCC believes converting energy-based revenues into a demand-based charge will create distortions for customers with variable load.[26]

**Q. Please summarize AWEC's testimony regarding the Company's calculation of the Capacity Reservation Charge.**

A. AWEC asserts that Reserved Capacity does not cause PacifiCorp to obtain 13 percent planning reserves. AWEC expresses its belief that it seems unlikely that Reserved Capacity would cause the Company to incur 100 percent of its FERC transmission cost.[27] AWEC's primary recommendation is to reject the Capacity Reservation Charge. To the extent the Commission agrees to implement the charge, AWEC recommends that the rates be indicative, any revenue collected be credited to the

[26] DCC/100, Cain/21-23.
[27] AWEC/200, Kaufman/34,35.

classes that pay them, and the calculation of the charge be modified to remove all generation costs and half of FERC transmission cost.[28]

**Q. Please summarize Vitesse's testimony regarding the Company's calculation of the Capacity Reservation Charge.**

A. Vitesse alleges that the Company's calculation does not follow cost causation principles, since the Company cannot directly assign the costs created to individual customers. Vitesse also questions inclusion of FERC transmission costs, because they are located in states other than Oregon and their purpose is not explicitly to serve very large customers, but they are more generically intended to improve system reliability, reduce transmission constraints, provide access to diverse generation resources, and improve the flow of energy throughout the Company's six-state system. Vitesse similarly raises concerns with including 11.5 percent of fixed generation costs since they are used to serve all customers in six states. Vitesse recommends using 40 percent of the Company's value to set the Capacity Reservation Charge, since 40 percent is the difference between an average customer load factor and 100 percent.[29]

**Q. Please respond to the arguments raised against the Company's Capacity Reservation Charge calculation.**

A. To serve very large customers at the scale of the requests the Company is receiving will require significant transmission and generation investments. The risk of these loads not materializing to the level planned for them is unprecedented and very different from the typical variation the Company sees from its existing customer base.

[28] AWEC/200, Kaufman/37-39.
[29] Vitesse/100, Coyle/45-49.

The Company will need to have bulk transmission capacity to bring energy to these customers. Setting the Capacity Reservation Charge at a level that recovers 100 percent of FERC transmission costs is therefore appropriate. Energy supply will also be needed to provide service to large new loads. There is greater flexibility with generation, since excess energy supply can be used at least to a certain point to make off-system sales. In recognition of this and the uncertainty that the Company carries with a very large load it may need to serve without much notice, only the portion of fixed generation costs that are related to planning reserves was included in the Capacity Reservation Charge's calculation. It is appropriate for the average cost assigned to Schedule 48 customers for these two categories to be used.

The Company plans its generation and bulk transmission as an integrated whole for all of its customers across the six states it serves. Customer rates are based upon allocations of these costs. It is appropriate to similarly base the Capacity Reservation Charge on an allocation of average system costs that are directly related to the investments required for Reserved Capacity.

Vitesse's recommendation to reduce the Capacity Reservation Charge to 40 percent and AWEC's recommendation to eliminate the generation component and reduce the transmission component by 50 percent are arbitrary and unsupported.

**Q. Do you agree with AWEC that the pricing for the Capacity Reservation Charge and Excess Demand Charge should be indicative until a more comprehensive review is completed?**

A. No. As stated earlier in my testimony, it is important that very large customers are able to make appropriate business decisions with transparency about rates associated

with reserving capacity in excess of their needs. Indicative pricing makes future outcomes for prospective customers and the Company less clear. It is uncertain how indicative pricing would work or to whom it would apply. AWEC has not clearly articulated how indicative pricing would function and why it is a reasonable step in light of the significant cost shifting that is likely to occur absent actual prices that would apply to very large customers.

## VIII. APPROPRIATENESS OF EXCESS DEMAND CHARGE DESIGN

**Q. Please summarize DCC's testimony regarding the Company's calculation of the Excess Demand Charge.**

A. DCC argues that the Excess Demand Charge violates ratemaking principles because it is not based upon coincident peak, since cost and reliability depend upon aggregate load and resources and not on the position of an individual customer. DCC disputes that a very large customer that exceeds its Reserved Capacity could cause significant costs and jeopardize system reliability. DCC considers the charge discriminatory and arbitrary.[30]

**Q. Please summarize AWEC's testimony regarding the Company's calculation of the Excess Demand Charge.**

A. AWEC notes that the Company has not incurred unauthorized use of transmission charges as the result of loads exceeding forecast. AWEC then compares the charge for exceeding reserved capacity on the transmission system in the Company's Open Access Transmission Tariff (OATT) to the proposed Excess Demand Charge. The OATT charge is two times the firm point-to-point charge for only the period of the

[30] DCC/100, Cain/24-27.

time of the exceedance. The transmission component of the proposed Excess Demand Charge is effectively 400 percent of the monthly firm point-to-point charge. AWEC shows that charges under the OATT would be only $12.26 for a MW exceeding a customer's reserved capacity for less than an hour, but the Excess Demand Charge would cost that same level of load $13,700, since it is a demand charge that is triggered if reached one time in the month for a 15-minute interval. AWEC consequently recommends reducing the Excess Demand Charge to 1.1 cents per kilowatt-hour (kWh).[31]

**Q. Please summarize Vitesse's testimony regarding the Company's calculation of the Excess Demand Charge.**

A. Vitesse argues that the proposed Excess Demand Charge is extremely punitive and recommends that 1.5 times multiplier of the Capacity Reservation Charge would be more appropriate.[32]

**Q. Please discuss comments from Staff on the Company's design of the Excess Demand Charge amount as a multiple of the Capacity Reservation Charge.**

A. Staff proposed no changes to the Company's design of the Excess Demand Charge.[33]

**Q. Please discuss the purpose of the Excess Demand Charge.**

A. When a very large customer contracts for service with the Company, it is critical that it not exceed the level of load for which it has contracted. The Company has not planned its system for a level of load that would exceed this contracted level. As the scale and number of very large loads increases, strict adherence to the contract

[31] AWEC/200, Kaufman/35-39.
[32] Vitesse/100, Coyle/49-50.
[33] Staff/700, Dlouhy/8.

capacity is of paramount importance. If very large customers exceed their contract capacity, costs could increase for all other customers and system reliability could be compromised. The Company recognizes that creating a Capacity Reservation Charge creates an incentive for customers to fully utilize their Reserved Capacity. In creating this incentive, it is important that the Company not create another incentive for customers to go over their contract level. The four times Capacity Reservation is intended to serve this purpose.

**Q. Do you agree with AWEC that the Excess Demand Charge should align with the OATT and be set as an energy charge?**

A. No. The Excess Demand Charge should align with the Capacity Reservation Charge and be billed on the same basis. The Excess Demand Charge should send a strong price signal for very large customers not to exceed their Reserved Capacity. At 1.1 cents per kWh, AWEC's proposed charge does not do this. It may in fact encourage very large customers to incur excess charges in lieu of paying the Capacity Reservation Charge by under-reserving capacity. It is also important to note that FERC transmission customers are different than very large retail customers. A retail customer requires both transmission delivery service and energy supply.

**Q. Do you agree with Vitesse that a 1.5 times multiplier of the Capacity Reservation Charge would be more appropriate?**

A. No. At 1.5 times the Capacity Reservation Charge, Vitesse's proposed Excess Demand Charge is only mildly more than the Capacity Reservation Charge. It is important that the Company send a strong price signal for very large customers not to violate the level of capacity they have requested under contract, especially because

incurrence of an Excess Demand Charge eliminates the possibility of a customer incurring a Capacity Reservation Charge during the subsequent 12-month or 36-month time period.

## IX. REDUCING AND CHANGING RESERVED CAPACITY

**Q. Please summarize Vitesse's testimony concerning reduction of a customer's Reserved Capacity.**

A. Vitesse incorrectly assumes that the proposed tariff, as it is written, would allow the Company to unilaterally reduce a customer's Reserved Capacity. Vitesse correctly notes that the proposed tariff imposes limitations on how quickly a customer could relinquish its Excess Reserved Capacity absent agreement by the Company. Vitesse expresses its belief that the Company should not be able to unilaterally take back Reserved Capacity after the customer had established itself in the service territory.[34]

**Q. Would the Company be able to unilaterally reduce a customer's Reserved Capacity?**

A. No. The proposed tariff language is clear that customers requiring 25 MW or more would be required to pay for Excess Reserved Capacity. A customer that decided it no longer needed the level of Reserved Capacity which it had contracted for would need to request a reduction to its Reserved Capacity from the Company. The customer could only reduce Reserved Capacity by the lesser of 10 percent or 50 MW per year, unless the Company agreed to a larger reduction. Reserved Capacity for very large customers would only be reduced by the customer's request—not by unilateral action by the Company.

[34] Vitesse/100, Coyle/38-41.

**Q. What is the intention of the proposed tariff language that outlines the limitations for reducing a customer's Reserved Capacity?**

A. The intention of the limitations is to ensure that investments made to energize a very large customer are properly recovered from that customer even if that customer rapidly scales down its load.

**Q. Can you provide an example of how these limitations could protect other customers?**

A. Yes. Suppose a collocation data center whose business model depends on providing computing service to other entities builds a 500 MW facility and the Company made major investments to serve this facility. This data center energizes and uses its full capacity for two years. In the third year, the data center's clients transfer their computing needs to other locations and the data center's load falls by half. Without the Company's proposed limitations in the tariff, this customer could lower its Reserved Capacity and shift the cost of the Company's investments onto other customers. This could be especially problematic if at some point in the future data center capacity becomes oversupplied and other entities cannot quickly step up to fill the void. Limiting how quickly the Reserved Capacity could be reduced by the customer's request ensures that an entity, like the data center in my example, appropriately pays for Excess Reserve Capacity for some period of time.

**Q. Why does the Company's proposed tariff allow Reserved Capacity to be reduced by a larger amount if mutually agreed to by the customer and Company?**

A. There may be no or minimal impact to cost recovery of the Company's investments if a customer in the same region wants to increase its capacity at the same time that the

requesting customers is seeking to relinquish its Reserved Capacity.

## X. DENIAL OF SERVICE AND SPECULATIVE LOADS

**Q. Please summarize parties' testimony concerning the Company's proposed tariff modifications for denial of service and speculative loads.**

A. Staff does not agree with the Company's proposal to grant flexibility in the tariff to the Company to deny requests based upon available capacity, because it believes this is inconsistent with the Company's obligation to serve. Staff does note that the Western United States is in a period of exceptional transmission tightness and capacity shortages. Staff recommends the Company give prospective new customers estimates of the timeline to connect or provide alternative points of interconnection.[35] Like Staff, Vitesse believes that the Company's proposed tariff revisions are inconsistent with its obligation to serve. Vitesse points to the Company's OATT which requires the Company to identify alternative points of interconnection(s) and requires the Company to consider generator interconnections with expected in-service dates up to 10 years in the future.[36] DCC recommends that the Company's proposed tariff language to consider some loads as "speculative" should either be removed or more clearly defined.[37] DCC also characterizes the Company's proposed language that it may deny load requests based upon available system capacity as discriminatory.[38]

[35] Staff/700, Dlouhy/11,12.
[36] Vitesse/100, Coyle/41-43.
[37] DCC/100, Cain/30-31.
[38] DCC/100, Cain/28.

**Q. Are there limitations to the Company's obligation to serve?**

A. Yes. Again, I am not an attorney, but it is my understanding that PacifiCorp is not required to provide services at any cost or under any circumstances to new customers. As I noted above, Oregon law specifically identifies that tariffs "for the provision of energy service that takes into account a customer's past energy usage and provides price incentives designed to encourage changes in the customer's energy usage that correspond to changes in the cost of providing energy" are not discriminatory.[39] The Company's Rule 13 tariff recognizes this principle. Section I.H of Rule 13 notes that "(t)he provisions of this Rule apply to Line Extensions that require standard construction and will produce sufficient revenues to cover the ongoing costs associated with them."

**Q. Is the intention of the Company's proposed tariff language enabling it to deny load requests depending upon available system capacity intended to allow the Company to deny requests that could be accommodated with a reasonable level of investment?**

A. No. If the Commission approved this change, it would not mean that the Company would deny requests that entail a reasonable level of investment and effort to provide access to available capacity in the region and secure energy supply for the applicant.

**Q. Why did the Company propose language enabling it to deny load requests depending upon available system capacity?**

A. At the scale of the load requests the Company is seeing, which can be for hundreds of MW to more than a GW, providing the requested service in a region could require

[39] ORS 757.310 (3)(c).

investment and efforts by the Company that are unreasonable. In some cases, this could mean new major interstate transmission lines that span hundreds of miles and cost billions of dollars.

**Q. Does the Company agree with DCC that it should define "speculative" in its tariff?**

A. No. While a list of technologies and business types could be spelled out in the tariff, that list would likely become quickly outdated given rapid changes that are happening in the economy.

**Q. Would an applicant have recourse if it felt that it was improperly considered to be speculative by the Company?**

A. Yes. An applicant could file a complaint to the Commission, and the Commission would consider the Company's rationale for considering the applicant speculative and redress the situation if it disagreed with the Company's judgment.

## XI. LARGE CUSTOMER ADVANCES

**Q. DCC recommends that the Commission reject the Company's proposal to require applicants with loads greater than 1,000 kilowatts to pay all of their Line Extension Advance upfront prior to construction. What is DCC's rationale?**

A. DCC claims that it is appropriate for large customers to pay half of the advance upfront and half after construction is completed to provide an incentive for the Company to complete the line extension in a timely manner. DCC asserts that the Company did not provide any evidence that the Company has any stranded line extension assets.[40]

[40] DCC/100, Cain/29,30.

**Q. Do you agree with DCC that having large customers only pay half of the advance upfront incentivizes the Company to compete its work faster?**

A. No. The Company is already incentivized to provide service to customers in a reasonable amount of time because of the potential revenue it will receive from large customers after they are energized.

**Q. Is the risk of stranded asset creation the only reason why payment for the Line Extension Allowance Advance should be required upfront?**

A. No. The carrying cost of constructing half of the line extension prior to receiving the remainder of funding from the customer is a significant cost for the Company. For very large customers, a line extension can cost tens of millions of dollars. Financing half of this for potentially a multi-year period across numerous projects can have a material impact on the Company's cash flow.

## XII. SUMMARY AND CONCLUSION

**Q. Please summarize your testimony.**

A. The Company's proposed Capacity Reservation Charge and Excess Capacity Charge along with proposed tariff rule changes are fair, just, reasonable, in the public interest and are critically needed to ensure that the risks of serving very large new loads are not borne by other customers. The Company recognizes that some flexibility is needed in the design of the Capacity Reservation Charge and proposes that a five percent buffer be used to give large customers some flexibility.

**Q. Does this conclude your reply testimony?**

A. Yes.

Docket No. UE 433
Exhibit PAC/3500
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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# Reply Testimony of Robert M. Meredith

**July 2024**

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## ATTACHED EXHIBITS

Exhibit PAC/3501—Updated Unbundled Results of Operations - Summary and Detail

Exhibit PAC/3502—Updated Functionalized Oregon Results of Operations Report

Exhibit PAC/3503—Updated Oregon Marginal Cost of Service Study Summary

Exhibit PAC/3504—Updated Unbundled Revenue Requirement Allocation

Exhibit PAC/3505—Updated Oregon Marginal Cost of Service Study

Exhibit PAC/3506—Updated Target Functionalized Revenues and Billing Determinants

Exhibit PAC/3507—Updated Estimated Effect of Proposed Rates and Proposed Adjustment Schedules

Exhibit PAC/3508—Updated Cost of Eliminating Payment Fees

**Q. Are you the same Robert M. Meredith that previously provided direct testimony in this case on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?**

A. Yes.

## I. PURPOSE AND SUMMARY

**Q. What is the purpose of your reply testimony?**

A. My reply testimony includes revised exhibits to reflect changes in the Oregon Results of Operations contained in the reply testimony of Company witness Sherona L. Cheung. Additionally, I respond to the testimonies of Staff of the Public Utility Commission of Oregon (Commission ) (Staff) witnesses Dr. Curtis Dlouhy, Bret Stevens, Michelle Scala, Kate Ayres, and Bret Farrell, Oregon Citizens' Utility Board (CUB) witnesses Sarah Wochele and Bob Jenks, Klamath Water User Association (KWUA) witness Lloyd C. Reed, Alliance of Western Energy Users (AWEC) witness Lance Kaufman, Walmart Inc. (Walmart) witness Eric S. Austin, Fred Meyer Stores (Fred Meyer) witness Justin Bieber, and Community Energy Project, Verde, and Coalition Communities of Color (Coalition) witnesses Charity Fain, Anahi Segovia Rodriguez, and Nikita Daryanani. My responses to the witnesses are organized by topic.

## II. UPDATED EXHIBITS

**Q. Have you prepared any updates to the exhibits filed with your reply testimony?**

A. Yes. Exhibits PAC/3501 through 3508 are updates to Exhibits PAC/1902, 1903, 1906, 1907, 1908, 1909, 1910 and 1917. The revised exhibits reflect changes in the Oregon Results of Operations as presented in Company witness Cheung's reply

testimony and exhibits. My updated exhibits also reflect some updates to the marginal cost of service study and costs of eliminating credit card payment fees that I address later in my testimony. The overall net rate increase shown in Exhibit PAC/3506 is $214.5 million or 11.9 percent.

**Q. Please summarize the Company's net rate spread proposal in this reply case.**

A. The Company continues to propose a cap of 1.25 times the overall net rate increase for each rate class. Table 1 below summarizes the Company's proposed net percentage price changes for the major rate schedule classes.

**TABLE 1**

| | |
|---|---|
| Residential Schedule 4 | 14.9% |
| General Service | |
| Schedule 23/723 (0-30kW) | 14.9% |
| Schedule 28/728 (31-200kW) | 4.5% |
| Schedule 30/730 (201-999kW) | 6.1% |
| Large General Service Schedules 47/747, 48/748 (≥1,000kW) | 9.8% |
| Agricultural Pumping Service Schedule 41/741 | 14.9% |
| Lighting Schedules | 3.0% |
| Overall | 11.9% |

**Q. Are you including updated tariffs at this time?**

A. No. The Company will file all necessary updated tariffs through a compliance filing at the conclusion of this case. Updated proposed rates are shown in my Exhibit PAC/3506.

## III. RESPONSE TO PARTIES' OPENING TESTIMONY

**Q. How do you organize your response to parties' opening testimony?**

A. I organize my response by topic, first addressing issues regarding the marginal cost of service study, and then addressing pricing-related matters. My lack of comments on any of the parties' testimony should not be interpreted as support or agreement.

### A. Marginal Cost of Generation

**Q. Please summarize Staff's recommendation for the marginal cost of energy.**

A. Staff recommends that the Company model the marginal cost of energy in the marginal cost of service study using generation resources from the Company's Integrated Resource Plan (IRP).[1]

**Q. Do you agree with Staff's recommendation to model the marginal cost of energy using generating resources from the preferred portfolio?**

A. No. The IRP includes a diverse portfolio of proxy generation resources that are all cost effective during various parts of the planning horizon. Including a complex portfolio of generation resources that would serve customer load throughout different time periods would add unnecessary complexity to the marginal cost of service model and make understanding the model less transparent and more cumbersome for interested parties. Furthermore, the IRP preferred portfolio does include the modeling of certain proxy generation resources over the planning horizon and an action plan which acts as an important guide for resource procurement. However, the procurement of generation resources depends on what is available in the market and assessments of economics of proposed projects based on actual costs. Wholesale

[1] Staff/1900, Stevens/12–15.

market purchases are the best representation available for the marginal cost of energy generated by the variety of resources required to meet customer load. In recent years, market prices have been volatile, however, the forecasted wholesale market prices included in the marginal cost of service study are relatively stable in the long run. The forecast considers additional generation resources that will be built and does not consider the unexpected constraints on the system that are contributing to the current volatility, therefore acting as a reasonable proxy for the marginal cost of energy.

**Q. Please summarize the recommendations for the allocation and functionalization of uncollectible costs in the marginal cost of service study.**

A. AWEC recommends that the Company assign 100 percent of the uncollectible expense to the customer billing function and that the Company use a five-year average of net write-offs to determine the allocation of uncollectible costs to each class.[2]

**Q. Do you agree with AWEC's recommendation to functionalize 100 percent of uncollectible costs as customer billing?**

A. Yes. The Company thinks this is reasonable.

**Q. Do you agree with AWEC's recommendation for the allocation of uncollectible costs?**

A. No. Due to the COVID-era restrictions on collections, the information from the past year is more indicative of conditions moving forward. A five-year average would result in an artificially low marginal uncollectible cost for residential customers.

[2] AWEC/205, Kaufman/115, 116.

**Q. What changes did the Company make to its marginal cost of service study presented in this reply testimony?**

A. The Company made three changes to the marginal cost of service study. The Company adopted AWEC's recommendation to functionalize 100 percent of uncollectible costs as customer billing. In making this change, the Company found that the uncollectible costs were not accurately included in the marginal cost of service model. The marginal cost of customer billing now correctly includes the marginal cost of uncollectible accounts. Additionally, the Company fixed a formula error in the marginal cost of energy that AWEC identified.[3]

**Q. Please summarize AWEC's assertion that costs are double counted for large customers in the cost of service study and its recommendation for how to resolve the alleged double counting.**

A. AWEC notes that as a result of recent tariff changes, Rule 13 no longer grants a line extension allowance for non-metering costs to customers that take service at transmission voltage or whose load size is greater than 25 megawatts (MW). Since local distribution and transmission costs are borne by these customers, AWEC asserts that it is unfair to allocate the return on and return of substations and local transmission to these classes. AWEC therefore recommends removing these costs for a portion of Schedule 48 Primary's distribution costs and removing the return on non-Federal Energy Regulatory Commission (FERC) transmission for part of the Schedule 48 Primary class and for all of the Schedule 48 transmission class.[4]

[3] AWEC/205, Kaufman/114.
[4] AWEC/200, Kaufman/24–26.

**Q. Does the Company think that this adjustment is warranted for the Schedule 48 primary class?**

A. No. While there is a large new primary voltage customer whose load is greater than 25 MW in the forecast period, this customer did receive a Line Extension Allowance, because it had a signed agreement with the Company prior to Rule 13 tariff changes which allowed it to have legacy status. As I noted in my direct testimony, there are no customers who would have energized in the forecast test period who would have received the modified Line Extension Allowance treatment.[5]

**Q. Does the Company agree with AWEC that an adjustment should be made to remove the return on and return of non-FERC transmission costs for the Schedule 48 transmission class?**

A. No. Providing no Line Extension Allowance for transmission voltage customers has been in the Company's tariff for many years. While these customers do pay for facilities required for their energization that are considered Direct Assigned, this does not mean that it is unfair to allocate local transmission facilities to them. If a transmission voltage customer energizes in an area with sufficient available capacity on the local transmission system, its load can be interconnected to that system, which may only necessitate constructing a short lateral line to provide them with service. Inasmuch as a transmission voltage customer chooses to energize in an area without facilities that have available capacity, that customer will need to pay for Direct Assigned facilities and a proportionate share of Network Upgrade facilities. The Company would fund the cost of Network Upgrade facilities that are not covered by

[5] PAC/1900, Meredith/26.

the applicant's proportionate share. This cost is caused by the new customer, and the capacity created by the Network Upgrade in the region, which is funded at least in part by the Company, may never be fully utilized or may not be fully utilized for many years. Transmission voltage customers do not receive Line Extension Allowances, but this does not mean that they do not utilize local transmission facilities that are funded, at least in part, by the Company. It is fair to continue the practice of allocating non-FERC transmission costs to these customers.

**Q. AWEC argues that the reserves value provided by energy storage is a capacity value and that the cost of a battery included in the marginal generation capacity cost should not be decremented for this value.[6] Do you agree?**

A. No. The benefit of operating reserves from batteries that is decremented in the Company's marginal generation capacity calculation is an energy value, since it reflects the incremental benefit of lower dispatch from freeing up cost-effective resources to generate energy to serve load or support off-system sales.

## B. Rate Spread

**Q. What is the basis for rate spread amongst the customer classes?**

A. In accordance with OAR 860-038-0240(3)(b), rates for any class of consumer must be based on the unbundled costs to serve that class.

**Q. Are other factors considered in determining ultimate rate spread?**

A. Yes, gradualism and rate shock are often considered in rate spread. The impact to all classes must be considered as any reduction to rate impact for one class results in an increase to the rate impact on another. PacifiCorp has proposed a cap of 1.25 times

[6] AWEC/200, Kaufman/24–26.

the overall percentage increase to any individual class, which the Company believes strikes a balance between the benefits of mitigating the largest potential rate impacts to some classes with the costs of other customer classes paying for that mitigation. For residential customers specifically, the Company proposed in the initially filed case to entirely eliminate the Rate Mitigation Adjustment (RMA) which would mean that the residential class would pay their full cost of service, neither paying for the mitigation to other classes nor receiving mitigation from other classes. In this reply case, the Company proposes a very small RMA credit to residential customers in order to keep their increase under the proposed 1.25 times the overall percentage cap, but this proposal is still a drastic decrease to the subsidy currently paid to residential customers and brings them very near to paying full cost of service with minimal impacts to other customers.

**Q. Please summarize the rate spread recommendations made by other parties.**

A. Staff recommends a slightly modified rate spread from the Company's proposal wherein a uniform floor would be applied to all classes under which a rate floor applies. Its recommendation would result in a higher increase for lighting customers, but is otherwise very similar to the Company's recommended rate spread.[7] Walmart does not oppose the Company's rate spread proposal, but recommends the Commission lower the RMA surcharge for Schedule 28 and 30 if a lower revenue requirement is approved.[8] Fred Meyer recommends that the cap on the base increase for customer classes be set at 1.50 times the average increase instead of the 1.25 times

[7] Staff/1900, Stevens/16–18.
[8] Walmart/100, Austin/15,16.

the base increase proposed by the Company.[9] In contrast to Fred Meyer, KWUA recommends a lower cap of 1.15 time the average base increase be applied.[10]

**Q. Please comment on other parties' rate spread testimony.**

A. Fred Meyer and KWUA each present opposing views of the level at which a cap on the base increase should be set. Fred Meyer advocates for a rate spread that favors mid-sized commercial customers. KWUA advocates for a rate spread that favors irrigation customers. Staff advocates for a rate spread that is nearly identical as the one the Company proposed, but assigns a higher increase to lighting customers. Considering the differing opinions on this topic, the Company's proposal seems to strike a reasonable balance amongst all customer concerns.

**Q. Do you oppose Staff's recommendation to assign a higher increase to the lighting class?**

A. I do. The lighting class has long paid more than its cost of service and currently pays the highest RMA of any class.[11] Giving the smallest increase to lighting customers is justified and the impact of doing so is *de minimis*, a fact that is shown by the very similar increases for all classes but lighting when comparing Staff's proposal to the Company's.[12]

**Q. Staff witness Scala states that the RMA does little to benefit schedule 4 customers.[13] How do you respond?**

A. It appears that that witness Scala may not fully understand the RMA. Base rates set in

[9] Fred Meyer/100, Bieber/5–16.
[10] KWUA/100, Reed/11,12.
[11] Schedule 299.
[12] Staff/1900, Stevens/16, 18 (Tables 3 and 4).
[13] Staff/300, Scala/29.

a general rate case are based on the cost of providing service to each customer class. To the extent Staff wishes to lower the rate impact to the residential class based on factors outside of the cost to provide service, the RMA would be the tool used to do so by providing residential customers with a per kilowatt-hour (kWh) credit and lowering the overall rates that residential customers would otherwise pay. The Company's reply rate spread proposal includes a very small RMA credit for the residential class as their unmitigated rate impact falls very close to the rate spread parameters proposed by the Company. However, Staff could propose a different rate spread which includes a higher residential RMA credit offset by RMA surcharges paid by other customer groups.

**Q. Does the Company consider affordability when determining rate spread?**

A. Yes. The Company considers the rate impact to all customers when proposing rate spread. All residential and business customers are facing rising costs, including energy costs. The Company's proposed rate spread is intended to balance the potential impacts to all classes while also trying to move customers closer to paying their full cost of service.

**C. Rate Spread and Rate Design for New Adjustment Schedules**

**Q. Please summarize the rate spread and rate design proposals made by other parties for new adjustment schedules.**

A. Fred Meyer proposes the Insurance Cost Adjustment be applied as a percentage of bill charge rather than a per kWh charge.[14] Fred Meyer also proposes that the Catastrophic Fire Fund Adjustment be applied as a demand based charge for rate

[14] Fred Meyer/100, Bieber/13–15.

schedules that have demand charges.[15] KWUA proposed the Catastrophic Fire Fund Adjustment use an equal cents per kWh rate spread instead of a distribution rate spread.[16]

**Q. The Company has withdrawn the proposed Catastrophic Fire Fund Adjustment in its reply case but please address why the Company prefers that the Insurance Cost Adjustment and Catastrophic Fire Fund Adjustment be billed on a per kWh basis.**

A. Almost all of the Company's adjustment schedules in its Oregon service territory are billed as per kWh surcharges and sur-credits. One of the primary reasons for this practice, particularly for non-residential consumers, is that per kWh based prices are non-bypassable by direct access consumers. With a per kWh surcharge, a similarly situated direct access consumer and cost of service consumer will pay the same amount. The Company therefore does not agree with Fred Meyer's proposals to bill the Insurance Cost Adjustment (and the Catastrophic Fire Fund Adjustment) on a different basis than per kWh.

## D. Residential Rate Design

**Q. Please summarize the residential rate spread positions taken and rate design proposals made by other parties for new adjustment schedules.**

A. Staff argues that the Company's proposed increase to the residential basic charge is too large, will make low usage customers and energy burdened households worse off, and will diminish the benefits of energy efficiency and weatherization for energy burdened customers. Staff expressed uncertainty with the relationship between

[15] Fred Meyer/100, Bieber/15, 16.
[16] KWUA/100, Reed/9, 11.

income and energy usage and noted that it believes that further analysis is needed.[17] Staff also argues that it is inappropriate to include the marginal commitment-related cost of distribution poles and conductor in the calculation of the residential basic charge, because it does not consider this to be a short-term cost. Staff also believes that the comparison to the residential basic charges of peer utilities should not consider consumer-owned utilities, since they are not regulated by the Commission. Staff recommends that the single-family basic charge be increased by $1 to $12 per month and the multi-family basic charge remain at $8 per month.[18] CUB recommends rejecting the Company's proposed residential basic charge increase for many of the same reasons given by Staff. Like Staff, CUB argues that the basic charge should only be benchmarked against other investor-owned utilities, and that certain costs should be excluded from what can be justified within a residential basic charge. CUB reasons that distribution poles and conductor and line transformer costs should not be included in the basic charge. Other arguments CUB raises include the following:

- High energy burdened customers may cut back on their usage by making sacrifices like not turning on air conditioning during the hottest months of the year, because they cannot afford to cool their home. A higher basic charge can harm low-income customers, by diminishing the financial benefit they would otherwise receive for this energy limiting behavior.
- An increase in the basic charge and an otherwise lower energy charge may lessen the bill savings from decarbonization investments such as energy efficiency and rooftop solar.

[17] Staff/300, Scala/32–35.
[18] Staff/1900, Stevens/19–25.

- Customers in competitive industries, such as grocery stores and gasoline stations, recover their costs through sales based upon output and not upon an access charge.[19]

**Q. Do you agree with Staff and CUB that a comparison of PacifiCorp's residential basic charge should exclude consumer-owned utilities, since those utilities are not regulated by the Oregon Public Utilities Commission?**

A. No. The rates set for consumer-owned utilities have been approved by their governing bodies who are commissioned with acting in the interest of their customers. In addition, consumer-owned utilities often serve more rural service areas where the fixed cost of providing service to residential customers is higher, which may arguably make them more similar to the Company than other investor-owned utilities that serve more metropolitan areas. The prices of consumer-owned utilities provide more useful information for the Commission to consider than comparison to other industries, as suggested by CUB.

**Q. Do either Staff or CUB present compelling evidence that low-income customers are disproportionately harmed by raising the basic charge instead of raising the energy charge as the Company proposes?**

A. No. They provide anecdotes and opinions but no clear evidence that raising the basic charge instead of raising the energy charge harms low-income customers more than it benefits them. Collecting the revenues the Company proposed to collect through increased basic charges through the energy charge instead would raise the energy charge by an additional 0.447 cents per kWh—nearly half a cent per kWh.

[19] CUB/200, Wochele-Jenks/3–14.

**Q. Can you please put the Company's proposed basic charge increase in context of the overall proposed increase for the typical residential customer?**

A. Yes. Under the Company's reply filing, the average single-family residential customer using 1,050 kWh per month would see a $23.22 per month increase. $5.00 or about 22 percent of that increase would be recovered through an increase in the basic charge with the remainder recovered through the energy charge. The Company's reply filing shows that the average multi-family residential customer using 650 kWh per month would see a $12.24 per month increase. $1.00 or about eight percent of that increase would be recovered through an increase in the basic charge.

**Q. Does the Company include appropriate cost categories in its calculation of the level that could be justified in a residential basic charge?**

A. Yes. The Company only included the marginal commitment costs of distribution facilities and customer service-related costs. Distribution poles and conductors and line transformers were a part of this calculation, but only the marginal commitment-related costs of these assets were included. Marginal demand-related distribution poles and conductor and line transformer costs were excluded. The differential in the single-family and multi-family basic charges is based upon the difference in providing service to these residential customer types from distribution line transformers and poles and conductor. If these cost categories were removed, there would no longer be a cost basis for charging multi-family customers a lower basic charge.

**Q. How do you respond to CUB's argument that raising the basic charge will diminish the savings a low-income customer may get from cutting back on energy usage?**

A. While that may be true, a lower energy charge may also be beneficial and help low-income customers better afford additional usage and not engage in energy limiting behavior that might be harmful to their health such as not heating and cooling their homes.

**Q. Please comment on CUB's concerns that a higher basic charge and a comparably lower energy charge erodes the savings customers can achieve from decarbonization investments.**

A. As noted earlier, most of the typical residential customer's bill increase under the Company's proposal would be recovered through an increase in the energy charge. The economics of such investments would therefore be strengthened rather than weakened. It is also important to consider that while higher energy charges may improve the economics of some decarbonization investments like rooftop solar or energy efficiency, they weaken other decarbonization investments like switching from a gas-fired water heater to a heat pump water heater or getting an electric vehicle. In a rising cost environment, it is important to balance recovery from volumetric charges with recovery from fixed charges to send appropriate price signals that encourage economically efficient behavior. The California Public Utilities Commission recognized this trade-off when it recently approved large increases to fixed charges for residential customers of the investor-owned utilities in that state.[20]

[20] Public Utilities Commission of the State of California, Rulemaking No. 22-07-005, Decision No, 22-07-005 (May 15, 2024).

**Q. How do you respond to the CUB's argument that competitive industries charge customers on sales volume and do not charge them access fees?**

A. While many competitive industries charge only for volumetric usage, it is also common for different industries to charge their customers on an entirely fixed basis or on a hybrid of both fixed and volumetric charges. For example, streaming video services usually charge a flat fee for all-you-can-watch television shows and movies on their platform. Internet providers similarly charge a flat per month fee based upon the speed of service. Home delivery subscription retailers and discount warehouse club retailers typically charge a fixed annual or monthly charge for membership and also charge for the actual goods sold. It is not uncommon for an electric utility to recover certain fixed costs from residential customer through a fixed basic charge as shown on the comparison of basic charges for the Company's peers in the region. Under the Company's proposal presented in reply testimony, residential basic charges would still only comprise about 10 percent of proposed residential class revenue.

**E. Low-Income Customer Concerns**

**Q. Please summarize CUB's testimony regarding actions the Company can do to help mitigate rate shock.**

A. CUB believes that the Company should take specific actions to mitigate rate shock that includes having the rate effective date fall outside of winter months, a shut off moratorium for six months following the effective date for a rate increase, report arrearage and disconnection data, Commission suspension or reduction of certain deferred accounts, and submitting a formal plan to the Commission that includes

educating customers about the Company's Low-Income Discount (LID) program, equal pay, energy efficiency and other options.[21]

**Q, Please summarize CUB's testimony regarding the Company's LID program.**

A. CUB believes that the implementation of the Company's LID program doesn't adequately reduce energy burden for the lowest income households and argues that the program doesn't target assistance that recognizes differential energy burden across all income-qualified customers.[22] As a result, CUB recommends that the Company provide deeper discounts and more targeted tiers.[23] CUB also notes that PacifiCorp should edit Schedule 7 to include clarification on the Company working with Oregon Housing and Community Services (OHCS) to appropriately place customers in the discount tier for which they qualify.[24] CUB also characterizes the LID as being a single tier program due to rate increases.[25]

**Q. Please summarize the Coalition's testimony regarding the Company's LID.**

A. The Coalition believes the Company's LID doesn't adequately provide the assistance low-income customers require to lower their energy burden and recommends the Company make several changes. The Coalition seeks to have additional tiers,[26] eliminate post-enrollment verification,[27] create a post-enrollment verification process for master-meter customers,[28] adopt an arrearage forgiveness program for the lowest

[21] CUB/100, Jenks/17.
[22] CUB/200, Wochele-Jenks/21.
[23] *Id.* at 39.
[24] *Id*. at 29.
[25] *Id*. at 37, 38, and 39.
[26] Coalition/100, Fain-Segovia Rodrigues-Daryanan/20.
[27] *Id*. at 22, 23, and 24.
[28] *Id.* at 24, 25.

tier,[29] eliminate disconnections for the lowest tier,[30] target energy efficiency and weatherization opportunities for high usage customers,[31] and prioritize efficiency programs to low-income customers in collaboration with the Energy Trust of Oregon.[32]

**Q. Please summarize Staff's testimony regarding the Company's LID.**

A. Staff recommends the Company make several changes to the LID, including the addition of a third discount tier providing at least a 60 percent discount for customers with an adjusted household income between zero and 10 percent State Median Income (SMI), an arrearage management program be attached to the LID program for customers below five percent SMI, engagement with parties before implementing a post enrollment verification process for LID participants, monitor and report high usage LID customers, engage community action program (CAP) agencies to help enrolling customers, and adjust the LID enrollment form to allow participants to utilize third parties to submit forms on their behalf.[33]

**Q. Do you agree with the parties' recommendation to provide deeper discounts to the Company's LID, specifically by including an additional tier?**

A. The Company will continue to support reasonable efforts to assist income constrained customers and is not against properly reviewing the Company's LID to make the program an essential tool for reducing customer energy burden. The Company believes the best way to evaluate the LID is through the Company's Energy Burden

[29] *Id*. at 25–31.
[30] *Id*. at 31–35.
[31] *Id*. at 36.
[32] *Id*. at 36.
[33] Staff/600, Ayres/3, 4, and 5.

Assessment (EBA), which is anticipated to be complete on October 1, 2024. This formal evaluation should be conducted prior to making any changes to the existing LID to ensure that decisions that impact customers receiving relief as well as all other customers paying for the program are data-driven.

Of note, the Company's survey to LID participants indicates that the program is presently having a significant impact on energy burden.

**Q. Do you agree with Staff that the LID is effectively a single tier due to rate increases?**

A. The Company disagrees with the characterization being made regarding the program. The Company's LID is a two-tier program giving relief to customers with respect to their household income and has helped reduce participating customers' energy burden. Absent the LID, participating customer energy burden would be greater.

**Q. Do you agree with Staff that the Company's Schedule 7 needs to be updated?**

A. Yes. The Company has contracted with OHCS to receive customer income data allowing the Company to enroll customers at the correct participating discount tier on the LID. The Company intends to make an update to Schedule 7 to reflect this contract.

**Q. Do you agree with the Coalition regarding post-enrollment verification?**

A. The Company is willing to continue having discussions with Staff and parties to determine the best course of action for post-enrollment. Conversations with the Company's Community Benefits and Impacts Advisory Group (CBIAG) have helped shape how post-enrollment will be rolled out and the Company anticipates having continued conversations to help inform the program moving forward, which would

include any updates to the post-enrollment process. With regards to master metered customers, the Company will consider the development of post-enrollment verification for those customers and will include it in its stakeholder conversations.

**Q. Do you agree with the parties' recommendation to implement an arrearage forgiveness or arrearage management component to the LID?**

A. The Company believes that any changes to the LID program should only take place after the Company's EBA is complete. The EBA will help advise on how effective the LID is at reducing energy burden, as well as looking at gaps in assistance and provide recommendations on how to meet lower energy burden targets.

**Q. Do you agree with the Coalition's recommendation that no disconnects should take place for the lowest income level on the LID program?**

A. The Company does not agree with placing a moratorium on disconnections for the lowest income levels on the LID program. Division 21 rules focusing on disconnection were recently reviewed and updated to provide additional protections for customers.[34] Additionally, the Company is hesitant to implement another moratorium on disconnections given the rise in arrearages following the moratorium put in place during the COVID-19 pandemic.

**Q. Do you agree with Staff's recommendation to monitor and report high usage LID customers?**

A. The Company is currently working with parties in docket UM 2211 on streamlining and updating reporting requirements and believes any new monitoring or reporting of data should be discussed in that docket.

[34] OAR Division 21.

**Q. Do you agree with Staff's recommendation to adjust the LID enrollment form to allow participants to utilize third parties to submit forms on their behalf?**

A. The Company currently allows agencies to submit forms electronically on a customer's behalf. This allows the agency to not only provide assistance to the customer but also ensure that the customer is placed on the correct LID tier. Customers who would like assistance submitting a form on their behalf can contact the Company or their energy assistance agency directly.

**Q. Please summarize CUB's testimony regarding disconnections and arrearages.**

A. CUB believes that the Division 21 rules do not protect low-income customers from being disconnected for non-payment.[35] Further, CUB suggests that data collection and reporting disconnections at a more granular level could help target programs and policies with regards to disconnection for non-payment, specifically providing data at a zip code level.[36] CUB also recommends that if the Company doesn't reduce disconnections that the Company should face a penalty.[37] CUB recommends that the Company address arrearages by working with stakeholders to create an arrearage forgiveness program.[38]

**Q. Please summarize Staff's testimony regarding arrearages and disconnections.**

A. Staff recommends the Company should engage with Staff, consumer advocates, CAP agency partners, and its CBIAG to discuss disconnections and arrearages to inform a crisis mitigation strategy to be brought before the Commission.[39] Staff also

[35] CUB/200, Wochele-Jenks/45–50.
[36] *Id*. at 52, 53.
[37] *Id*. at 54.
[38] *Id*. at 55.
[39] Staff/300, Scala/6, 7.

recommends that LID participants with a past-due balance over six times the monthly average bill for the account no longer accumulate debt and have an internal arrearage management review.[40]

**Q. Please provide your thoughts with respect to the Company's disconnections and arrearages.**

A. Disconnection of service for non-payment is the Company's last course of action to stop customer balances from growing higher. The Company attempts to contact customers prior to disconnection in an attempt to make progress towards reducing the customer balance and avoiding disconnection. Over the last four years, following the moratorium on disconnections and then a continued moratorium for specifically targeted customers during the Division 21 rulemaking process, more and more customers found themselves further behind. The Company's LID program helped lower energy burden for low-income customers. The changes in Division 21 provided additional protection for customers prior to disconnection and made it easier for customers to have service restored. Present elevated levels of disconnections are the result of the Company playing catch-up after certain protections were lifted and working through a backlog of past due customer accounts.

**Q. Do you agree with Staff's recommendation for a crisis mitigation strategy?**

A. The Company believes that further discussion would be advantageous to try and determine how disconnections can be reduced and arrearages alleviated. The Company doesn't commit to a specific strategy at this time.

[40] *Id*. at 25, 26.

**Q. Do you agree with Staff's recommendation to halt disconnections for customers with past due balances six times their monthly average for an internal management review?**

A. The Company doesn't agree with halting disconnection in these cases. The Company provides ample notification to customers in advance of disconnection to have the customer contact the Company to enter into or renegotiate payment arrangements, discuss assistance resources, identify the customer as a low-income customer for Division 21 protections and enrollment in the LID program, and provide information on medical certificates. It's not clear what an internal management review of the customer's account will accomplish if the customer doesn't already respond to the Company's outreach through disconnection notices, outbound calls, text messages, and/or emails. Further, the Company has seen a significant increase in arrearages following the COVID-19 disconnection moratorium and is hesitant to implement any further moratoriums that might further increase arrearages and customer energy burden.

**Q. Do you agree with CUB that the Company should face a penalty for not reducing disconnections?**

A. No, the Company does not agree with a penalty if disconnections are not reduced. Disconnecting customers for non-payment, while a last resort, is an important tool for ensuring that customers pay their electric bills. Unreasonably hampering the Company's effort to collect from customers who have not paid their bill can raise costs for all customers. Such action could also cause customers who are past due to fall further behind. The Company encourages further discussion with Staff,

community partners, and other stakeholders on how the Company can help reduce disconnections.

**F. Removal of Fees for Payment**

**Q. Please summarize Staff's testimony regarding the Company's request to remove customer payment fees.**

A. Staff expresses its willingness to remove residential card payment and paystation fees if the Company provides further support for the removal in reply testimony.[41] Staff disagrees with eliminating non-residential payment fees.[42] Staff objects to the Company's Test Year forecast and recommends a three-year average for the fee count for pay station and residential card payments while removing non-residential payment fees from the Company's calculated adjustment to revenue requirement.[43]

**Q. Why does the Company propose removing fees for customers who pay at a pay station or with a credit or debit card?**

A. As stated in direct testimony, customers who use pay stations to make a payment can be in a crisis and need to make a fast payment to restore their power after a shut-off for non-payment. They may also be un-banked and do not have the ability to pay with a check or an electronic draft. Customers who pay their power bill with a credit card may be doing so because they are in a tight spot financially and do not have the cash on hand to pay from a bank account. For vulnerable customers experiencing financial constraints, facing additional fees to pay their power bills can set them back further

[41] Staff/900, Farrell/9.
[42] *Id*. at 9.
[43] *Id*. at 11.

and increase their energy burden. Removing the fees can make these methods of payment more accessible and more feasible for vulnerable customers.

**Q. Do you agree with Staff's recommendation to use a three-year average for fee counts?**

A. The Company agrees with using a three-year average for the pay station and card counts. The Company agrees with Staff that the base period was a significant outlier and upon further analysis of the Company's fee counts found that the 2023 base period data that was presented in the Company's direct testimony was inaccurate. The Company includes in this reply testimony the correct data for 2023 and suggests using a three-year average as recommended by Staff using the years 2021 through 2023. The Company proposes an adjustment to revenue requirement of $1.6 million in fees for using pay stations and paying with a card. Exhibit PAC/3507 shows the updated details for payment fees for 2021 through 2023.

**Q. Do you agree with Staff that non-residential payment fees should be excluded?**

A. The Company believes that if payment fees are eliminated, they should be eliminated for all customers. The Company contracts with a specific card vendor for all six states that PacifiCorp serves and cannot separate residential from non-residential payments without costs being incurred. The Company's pay station vendors cannot separate residential and non-residential payments, so eliminating only the residential fees may impact vendor negotiations. It is also the Company's understanding that Portland General Electric Company (PGE) and Northwest Natural waive payment fees for non-residential accounts. Additionally, after the corrections and revisions described above, the cost the Company calculates for waiving non-residential fees is

significantly less than what I presented in direct testimony.[44] Eliminating payment fees to all customers would allow for consistency, reduce system costs, and avoid the potential vendor conflict.

## G. Time of Use (TOU)

**Q. How does the Company respond to Staff's concerns that the Company's enrollment in the residential TOU pilot was not as robust as the enrollment in PGE's residential TOU program?[45]**

A. PGE's customer base is vastly different than PacifiCorp's. PGE serves a largely urban area. PacifiCorp service territory is more spread out and diverse. PacifiCorp's enrollment in special rate programs should not be directly compared to PGE's enrollment. The Company believes it adequately notified customers about a pilot program at the time it became available. If the residential TOU rate is converted to a permanent program as proposed, the Company plans to continue promoting the program to encourage additional enrollment.

**Q. Staff has concerns about cost shifting from the TOU program and the potential for a "needle peak" to develop if enrollment reaches a high enough level.[46] Does the Company share these concerns?**

A. Yes. The Company agrees that if its TOU program grows to a significant size, cost shifting and the potential snap-back effect that may occur when the off-peak period commences could have a material impact.

[44] In my direct testimony, the cost of waiving non-residential payments was incorrectly stated as $2,068,619. PAC/1917, Meredith/1. After fixing an error and using a three-year average, this value has been updated to $181,804.
[45] Staff/700, Dlouhy/24–26.
[46] Staff/700, Dlouhy/27–31.

**Q. How do you think the Company should evaluate the residential time of use program in the future?**

A. When and if participation in the program grows to a point where adoption is at a significant level, such as five or 10 percent, it recommends that the program be put on a separate cost of service class and evaluated to ensure that any cost shifting is minimized. In the Company's Idaho service territory, its time of use program, Idaho Schedule 36, has about 14 percent adoption. Schedule 36 has been on its own cost of service class for many years.

## H. Other Issues

**Q. Walmart has concerns with the availability of an ongoing rate that works well with electric vehicle fast chargers.[47] Does the Company have a rate schedule which is beneficial to fast electric vehicle charging?**

A. Yes. Schedule 29, General Service Time of Use, is currently available as a pilot rate and I have proposed in my direct testimony to make this a permanent rate. Schedule 29 is favorable to low-load factor electric vehicle charging since it does not have demand charges.

**Q. Please summarize the position taken by parties in their opening testimony regarding the treatment of any revenue the Company may receive from its proposed Capacity Reservation Charge and Excess Demand Charge.**

A. Staff recommends that this revenue be tracked through a deferral and refunded back to each customer class on an equal percentage of revenue basis.[48] CUB similarly recommends that revenue received from these charges should be tracked via a

[47] Walmart/100, Austin/16–20.
[48] Staff/700, Dlouhy/8, 9.

deferral and credited against rates in the future.[49] Vitesse proposes that revenues generated from the charges be returned back to large customers on Schedule 47 and Schedule 48.[50]

**Q. Does the Company agree that the revenue from the Capacity Reservation Charge and Excess Demand Charge should be deferred and refunded back to customers in between years when the Company is not in for a rate case?**

A. No. The Company recommends that any revenue that is collected in the historic base period of a general rate case would be a revenue credit that would offset the revenue required from all classes. The Company does not think that all revenue collected from these charges in between rate cases should be deferred and refunded to customers for two reasons. First, the Company believes that it is likely that the Company will not collect any revenue or a *de minimis* level of revenue from these charges. The Company will provide large customers a six-month period to re-negotiate their Reserved Capacity with the Company and thereby presumably lower or eliminate these potential charges. The Company does not forecast any revenues from these charges in the 2025 test year for this case. Also in response to parties' opening testimony, the Company has modified its proposal in the reply testimony of Company witness Anna DeMers to only charge the Capacity Reservation Charge if Excess Reserved Capacity is greater than five percent of Reserved Capacity. The Company will only collect these new charges if a large customer's load forecast is off by more than five percent.

[49] CUB/300, Garrett/11.
[50] Vitesse/100, Coyle/51.

Second, if a large customer pays either of these charges, it will mean that the Company has either planned for and built facilities to serve load from the large customer that has not materialized or the large customer is using more than the level for which it has contracted. In either event, the Company will likely have incurred large offsetting expenses that would not be recovered immediately from customers outside of a rate case. For example, the Company may have invested in significant network upgrades that were not paid for by the large customer to energize its load.

**Q. To the extent the Commission requires the Company to defer this revenue and pass it back to customers, do you have recommendations on how that should occur?**

A. Yes. If the Commission requires this, the Company recommends that the deferral accumulate until the next general rate case and then the refund be amortized over an appropriate period of time to all customers on an equal cents per kWh basis. After the next general rate case concludes, the revenue from these charges would be built into base rates and no further deferral would be required. The Company does not think that an automatic adjustment clause should be instituted for this item, because it would add unnecessary additional administrative burden for the Company, Staff, and stakeholders. The Company recommends passing back the revenue to all customers, since all customers share in the offsetting costs that occur.

**Q. Does this conclude your reply testimony?**

A. Yes.

Docket No. UE 433
Exhibit PAC/3501
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Robert M. Meredith**

**Updated Unbundled Results of Operations - Summary and Detail**

**July 2024**

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2025 Forecast

| Function | | | Revenue Requirement |
|---|---|---|---|
| Production | | $ | 940,921,712 |
| Transmission | | $ | 313,464,185 |
| Distribution | | $ | 450,631,390 |
| Distribution-Lighting | | $ | 3,580,642 |
| Distribution Total | | $ | 454,212,031 |
| Ancillary | | $ | 24,138,546 |
| Customer Billing | | $ | 24,696,163 |
| Customer Metering | | $ | 18,826,668 |
| Customer Other | | $ | 9,194,363 |
| Retail Service | a | $ | - |
| Public Purposes | b | $ | - |
| Total State of Oregon | | $ | 1,785,453,669 |

a - Retail Services are conducted as unregulated activities.
b - DSM is collected by a separate tariff.
Public Purposes are collected by a separate tariff.

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2025 Forecast

| | | ROR | ROE | Total $ | Production | Transmission | Distribution | Distribution-Lighting | Ancillary | Customer Billing | Customer Metering | Customer Other | Distribution Components: Poles & Wires | Distribution Components: Poles & Wires-Lighting | Distribution Components: Franchise Fees |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Functionalized Situs Revenues @ Earned | 6.02% | 6.76% | 1,680,937,338 | 920,460,117 | 269,569,194 | 414,037,527 | 3,220,146 | 24,138,546 | 23,504,891 | 17,013,678 | 8,993,240 | 368,681,802 | 2,867,395 | 45,708,476 |
| 2 | System Allocated Revenues | | | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | Total Oregon General Business Revenue | | | 1,680,937,338 | 920,460,117 | 269,569,194 | 414,037,527 | 3,220,146 | 24,138,546 | 23,504,891 | 17,013,678 | 8,993,240 | 368,681,802 | 2,867,395 | 45,708,476 |
| 4 | | | | | | | | | | | | | | | |
| 5 | Target Increase in Return | 7.47% | 9.65% | 76,086,873 | 15,343,073 | 32,914,541 | 25,663,301 | 252,816 | - | 402,864 | 1,359,466 | 150,812 | 25,663,301 | 252,816 | - |
| 6 | | | | | | | | | | | | | | | |
| 7 | Add | | | | | | | | | | | | | | |
| 8 | Uncollectible Expense | | | 654,012 | | | | | | 654,012 | | | | | |
| 9 | Franchise Tax | | | 2,378,901 | | | 2,355,694 | 23,207 | | | | | | | 2,378,901 |
| 10 | Other Revenue Based Taxes | | | 590,378 | 116,308 | 249,509 | 208,008 | 2,049 | - | 3,054 | 10,305 | 1,143 | 194,541 | 1,916 | 13,600 |
| 11 | Inc Taxes - State | | | 4,580,544 | 923,676 | 1,981,505 | 1,544,969 | 15,220 | - | 24,253 | 81,842 | 9,079 | 1,544,969 | 15,220 | - |
| 12 | Inc Taxes - Federal | | | 20,225,624 | 4,078,538 | 8,749,435 | 6,821,890 | 67,204 | - | 107,090 | 361,377 | 40,089 | 6,821,890 | 67,204 | - |
| 13 | Total Increase Needed | | | 104,516,331 | 20,461,596 | 43,894,991 | 36,593,862 | 360,496 | - | 1,191,273 | 1,812,990 | 201,123 | 34,224,701 | 337,157 | 2,392,500 |
| 14 | | | | | | | | | | | | | | | |
| 15 | Total Oregon General Business Revenue @ | 7.47% | 9.65% | 1,785,453,669 | 940,921,712 | 313,464,185 | 450,631,390 | 3,580,642 | 24,138,546 | 24,696,163 | 18,826,668 | 9,194,363 | 402,906,503 | 3,204,552 | 48,100,976 |
| 16 | Less: System Allocated Revenues | | | - | - | - | - | - | - | - | - | - | - | - | - |
| 17 | Total Unbundled Revenue Requirement | | | 1,785,453,669 | 940,921,712 | 313,464,185 | 450,631,390 | 3,580,642 | 24,138,546 | 24,696,163 | 18,826,668 | 9,194,363 | 402,906,503 | 3,204,552 | 48,100,976 |
| 18 | | | | | | | | | | | | | | | |
| 19 | Rate Base | | | 5,269,659,203 | 1,062,637,508 | 2,279,610,271 | 1,777,400,558 | 17,509,642 | - | 27,901,730 | 94,154,513 | 10,444,981 | 1,777,400,558 | 17,509,642 | - |
| | | | | | 20.17% | 43.26% | 33.73% | 0.33% | 0.00% | 0.53% | 1.79% | 0.20% | 33.73% | 0.33% | 0.00% |

Notes:
Row 9: Franchise Tax @ 2.28%
Row 11: Inc Taxes - State 4.54%
Row 12: Inc Taxes - Federal 21.00%

Docket No. UE 433
Exhibit PAC/3502
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Robert M. Meredith**

**Updated Functionalized Oregon Results of Operations Report**

**July 2024**

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Unbundled Results of Operations
12 Months Ended December 31, 2025 Forecast

| | | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Other |
|---|---|---|---|---|---|---|---|---|---|---|
| Operating Revenues | | | | | | | | | | |
| | General Business Revenues | 1,680,937,338 | 920,460,117 | 269,569,194 | 414,037,527 | 3,220,146 | 24,138,546 | 23,504,891 | 17,013,678 | 8,993,240 |
| | Special Sales | 88,412,673 | 88,412,673 | - | - | - | - | - | - | - |
| | Other Operating Revenues | 71,672,999 | 31,706,809 | 51,401,773 | 5,575,537 | 2,917 | (24,138,546) | 6,262,277 | 367,668 | 494,564 |
| | Total Operating Revenues | 1,841,023,010 | 1,040,579,598 | 320,970,967 | 419,613,065 | 3,223,063 | - | 29,767,167 | 17,381,346 | 9,487,804 |
| Operating Expenses | | | | | | | | | | |
| | Steam Production | 276,893,892 | 276,893,892 | - | - | - | - | - | - | - |
| | Nuclear Production | - | - | - | - | - | - | - | - | - |
| | Hydro Production | 13,594,108 | 13,594,108 | - | - | - | - | - | - | - |
| | Other Power Supply | 547,485,749 | 547,485,749 | - | - | - | - | - | - | - |
| | ECD | - | - | - | - | - | - | - | - | - |
| | Transmission | 71,121,871 | 248,005 | 70,873,866 | - | - | - | - | - | - |
| | Distribution | 114,542,254 | - | - | 111,754,564 | 940,230 | - | - | 1,847,460 | - |
| | Customer Accounts | 28,163,160 | - | - | - | - | - | 21,931,119 | 3,298,853 | 2,933,188 |
| | Customer Service | 5,298,846 | - | - | 2,475,650 | - | - | - | - | 2,823,196 |
| | Sales | - | - | - | - | - | - | - | - | - |
| | Administrative & General | 61,765,305 | 12,176,434 | 5,825,825 | 40,436,765 | 69,300 | - | 1,587,593 | 1,121,337 | 548,050 |
| | Total O & M Expenses | 1,118,865,185 | 850,398,187 | 76,699,691 | 154,666,979 | 1,009,530 | - | 23,518,712 | 6,267,650 | 6,304,434 |
| | Depreciation | 317,074,767 | 191,324,243 | 57,044,902 | 64,945,455 | 786,058 | - | 659,438 | 2,050,031 | 264,640 |
| | Amortization Expense | 27,809,318 | 6,803,407 | 1,732,013 | 12,975,823 | 32,559 | - | 2,862,151 | 1,585,989 | 1,817,376 |
| | Taxes Other Than Income | 100,593,896 | 23,179,856 | 15,247,253 | 60,769,191 | 163,210 | - | 333,950 | 725,508 | 174,928 |
| | Income Taxes - Federal | (38,449,492) | (78,530,650) | 14,157,302 | 23,635,918 | 471,023 | - | 442,876 | 1,398,361 | (24,322) |
| | Income Taxes - State | 6,408,557 | 3,622,233 | 1,117,292 | 1,460,663 | 11,219 | - | 103,619 | 60,504 | 33,027 |
| | Income Taxes - Def Net | (8,550,148) | (20,109,266) | 17,720,351 | (5,935,568) | (304,841) | - | 166,380 | (376,004) | 288,800 |
| | Investment Tax Credit Adj. | - | - | - | - | - | - | - | - | - |
| | Misc Revenue & Expense | (30,006) | (92,792) | (9,553) | 72,340 | - | - | - | - | - |
| | Total Operating Expenses | 1,523,722,077 | 976,595,219 | 183,709,251 | 312,590,801 | 2,168,758 | - | 28,087,126 | 11,712,039 | 8,858,882 |
| Operating Revenue for Return | | 317,300,933 | 63,984,379 | 137,261,716 | 107,022,264 | 1,054,305 | - | 1,680,041 | 5,669,307 | 628,922 |
| Rate Base | | | | | | | | | | |
| | Electric Plant in Service | 10,383,366,153 | 4,090,456,990 | 3,057,258,257 | 2,970,162,905 | 32,828,594 | - | 55,945,387 | 144,451,516 | 32,262,503 |
| | Plant Held for Future Use | - | (79,561) | 264,553 | (175,384) | - | - | (4,456) | (5,152) | - |
| | Misc Deferred Debits | 96,395,604 | 80,150,931 | 4,335,282 | 9,211,018 | 69,744 | - | 1,586,185 | 464,089 | 578,354 |
| | Elec Plant Acq Adj | 703,248 | 703,248 | - | - | - | - | - | - | - |
| | Nuclear Fuel | - | - | - | - | - | - | - | - | - |
| | Prepayments | 16,838,184 | 7,370,462 | 1,826,817 | 5,913,318 | 44,788 | - | 1,015,005 | 297,641 | 370,153 |
| | Fuel Stock | 43,544,178 | 43,544,178 | - | - | - | - | - | - | - |
| | Material & Supplies | 129,822,071 | 95,215,135 | 1,936,867 | 31,763,560 | - | - | - | 906,510 | - |
| | Working Capital | 48,204,849 | 26,559,060 | 4,494,545 | 13,964,519 | 100,599 | - | 1,882,486 | 590,997 | 612,643 |
| | Weatherization Loans | - | - | - | - | - | - | - | - | - |
| | Miscellaneous Rate Base | (98,566) | (98,566) | - | - | - | - | - | - | - |
| | Total Electric Plant | 10,718,775,721 | 4,343,821,878 | 3,070,116,321 | 3,030,839,935 | 33,043,725 | - | 60,424,608 | 146,705,601 | 33,823,653 |
| Rate Base Deductions | | | | | | | | | | |
| | Accum Prov For Depr | (4,043,129,802) | (2,063,552,941) | (670,080,406) | (1,249,778,570) | (15,913,181) | - | (3,620,682) | (38,676,837) | (1,507,185) |
| | Accum Prov For Amort | (229,765,382) | (76,209,650) | (52,674,821) | (37,033,505) | (57,315) | - | (28,192,106) | (15,047,019) | (20,550,964) |
| | Accum Def Income Taxes | (696,410,395) | (712,207,010) | (25,821,278) | 41,042,129 | 513,478 | - | (289,755) | 1,519,301 | (1,167,261) |
| | Unamortized ITC | (40,918) | (17,136) | (2,957) | (16,110) | (122) | - | (2,772) | (811) | (1,011) |
| | Customer Adv for Const | (46,658,522) | - | (41,481,126) | (4,912,218) | (55,062) | - | - | (210,115) | - |
| | Customer Service Deposits | - | - | - | - | - | - | - | - | - |
| | Misc. Rate Base Deductions | (433,111,498) | (429,197,632) | (445,461) | (2,741,104) | (21,881) | - | (417,563) | (135,607) | (152,252) |
| | Total Rate Base Deductions | (5,449,116,517) | (3,281,184,369) | (790,506,049) | (1,253,439,377) | (15,534,083) | - | (32,522,878) | (52,551,088) | (23,378,672) |
| Total Rate Base | | 5,269,659,203 | 1,062,637,508 | 2,279,610,271 | 1,777,400,558 | 17,509,642 | - | 27,901,730 | 94,154,513 | 10,444,981 |
| Return on Rate Base | | 6.0213% | 6.0213% | 6.0213% | 6.0213% | 6.0213% | 6.0213% | 6.0213% | 6.0213% | 6.0213% |
| Return on Equity | | 6.7623% | 6.7623% | 6.7623% | 6.7623% | 6.7623% | 6.7623% | 6.7623% | 6.7623% | 6.7623% |

2020 PROTOCOL
RESULTS OF OPERATIONS SUMMARY
12 Months Ended December 31, 2025 Forecast

| | | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Operating Revenues | General Business Revenues | 1,680,937,338 | 920,460,117 | 269,569,194 | 414,037,527 | 3,220,146 | 24,138,546 | 23,504,891 | 17,013,678 | 8,993,240 | 0 |
| | General Business Revenues | - | - | - | - | - | - | - | - | - | - |
| | Interdepartmental | - | - | - | - | - | - | - | - | - | - |
| | Special Sales | 88,412,673 | 88,412,673 | - | - | - | - | - | - | - | - |
| | Other Operating Revenues | 71,672,999 | 31,706,809 | 51,401,773 | 5,575,537 | 2,917 | (24,138,546) | 6,262,277 | 367,668 | 494,564 | - |
| | Total Operating Revenues | 1,841,023,010 | 1,040,579,598 | 320,970,967 | 419,613,065 | 3,223,063 | - | 29,767,167 | 17,381,346 | 9,487,804 | 0 |
| Operating Expenses | | | | | | | | | | | |
| | Steam Production | 276,893,892 | 276,893,892 | - | - | - | - | - | - | - | - |
| Operating Expenses | Nuclear Production | - | - | - | - | - | - | - | - | - | - |
| | Hydro Production | 13,594,108 | 13,594,108 | - | - | - | - | - | - | - | - |
| | Other Power Supply | 547,485,749 | 547,485,749 | - | - | - | - | - | - | - | - |
| | ECD | - | - | - | - | - | - | - | - | - | - |
| | Transmission | 71,121,871 | 248,005 | 70,873,866 | - | - | - | - | - | - | - |
| | Distribution | 114,542,254 | - | - | 111,754,564 | 940,230 | - | - | 1,847,460 | - | - |
| | Customer Accounts | 28,163,160 | - | - | - | - | - | 21,931,119 | 3,298,853 | 2,933,188 | - |
| | Customer Service | 5,298,846 | - | - | 2,475,650 | - | - | - | - | 2,823,196 | - |
| | Sales | - | - | - | - | - | - | - | - | - | - |
| | Administrative & General | 61,765,305 | 12,176,434 | 5,825,825 | 40,436,765 | 69,300 | - | 1,587,593 | 1,121,337 | 548,050 | - |
| | Total O & M Expenses | 1,118,865,185 | 850,398,187 | 76,699,691 | 154,666,979 | 1,009,530 | - | 23,518,712 | 6,267,650 | 6,304,434 | - |
| | Depreciation | 317,074,767 | 191,324,243 | 57,044,902 | 64,945,455 | 786,058 | - | 659,438 | 2,050,031 | 264,640 | - |
| | Amortization Expense | 27,809,318 | 6,803,407 | 1,732,013 | 12,975,823 | 32,559 | - | 2,862,151 | 1,585,989 | 1,817,376 | - |
| | Taxes Other Than Income | 100,593,896 | 23,179,856 | 15,247,253 | 60,769,191 | 163,210 | - | 333,950 | 725,508 | 174,928 | 0 |
| | Income Taxes - Federal | (38,449,492) | (78,530,650) | 14,157,302 | 23,635,918 | 471,023 | - | 442,876 | 1,398,361 | (24,322) | 0 |
| | Income Taxes - State | 6,408,557 | 3,622,233 | 1,117,292 | 1,460,663 | 11,219 | - | 103,619 | 60,504 | 33,027 | 0 |
| | Income Taxes - Def Net | (8,550,148) | (20,109,266) | 17,720,351 | (5,935,568) | (304,841) | - | 166,380 | (376,004) | 288,800 | - |
| | Investment Tax Credit Adj. | - | - | - | - | - | - | - | - | - | - |
| | Misc Revenue & Expense | (30,006) | (92,792) | (9,553) | 72,340 | - | - | - | - | - | - |
| | Total Operating Expenses | 1,523,722,077 | 976,595,219 | 183,709,251 | 312,590,801 | 2,168,758 | - | 28,087,126 | 11,712,039 | 8,858,882 | 0 |
| Operating Revenue for Return | | 317,300,933 | 63,984,379 | 137,261,716 | 107,022,264 | 1,054,305 | - | 1,680,041 | 5,669,307 | 628,922 | 0 |
| Rate Base | | | | | | | | | | | |
| | Electric Plant in Service | 10,383,366,153 | 4,090,456,990 | 3,057,258,257 | 2,970,162,905 | 32,828,594 | - | 55,945,387 | 144,451,516 | 32,262,503 | - |
| Rate Base | Plant Held for Future Use | - | (79,561) | 264,553 | (175,384) | - | - | (4,456) | (5,152) | - | - |
| | Misc Deferred Debits | 96,395,604 | 80,150,931 | 4,335,282 | 9,211,018 | 69,744 | - | 1,586,185 | 464,089 | 578,354 | - |
| | Elec Plant Acq Adj | 703,248 | 703,248 | - | - | - | - | - | - | - | - |
| | Nuclear Fuel | - | - | - | - | - | - | - | - | - | - |
| | Prepayments | 16,838,184 | 7,370,462 | 1,826,817 | 5,913,318 | 44,788 | - | 1,015,005 | 297,641 | 370,153 | - |
| | Fuel Stock | 43,544,178 | 43,544,178 | - | - | - | - | - | - | - | - |
| | Material & Supplies | 129,822,071 | 95,215,135 | 1,936,867 | 31,763,560 | - | - | - | 906,510 | - | - |
| | Working Capital | 48,204,849 | 26,559,060 | 4,494,545 | 13,964,519 | 100,599 | - | 1,882,486 | 590,997 | 612,643 | 0 |
| | Weatherization Loans | - | - | - | - | - | - | - | - | - | - |
| | Miscellaneous Rate Base | (98,566) | (98,566) | - | - | - | - | - | - | - | - |
| | Total Electric Plant | 10,718,775,721 | 4,343,821,878 | 3,070,116,321 | 3,030,839,935 | 33,043,725 | - | 60,424,608 | 146,705,601 | 33,823,653 | 0 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Rate Base Deductions | | | | | | | | | | | |
| | Accum Prov For Depr | (4,043,129,802) | (2,063,552,941) | (670,080,406) | (1,249,778,570) | (15,913,181) | - | (3,620,682) | (38,676,837) | (1,507,185) | - |
| Rate Base Deduction | Accum Prov For Amort | (229,765,382) | (76,209,650) | (52,674,821) | (37,033,505) | (57,315) | - | (28,192,106) | (15,047,019) | (20,550,964) | - |
| | Accum Def Income Taxes | (696,410,395) | (712,207,010) | (25,821,278) | 41,042,129 | 513,478 | - | (289,755) | 1,519,301 | (1,167,261) | - |
| | Unamortized ITC | (40,918) | (17,136) | (2,957) | (16,110) | (122) | - | (2,772) | (811) | (1,011) | - |
| | Customer Adv for Const | (46,658,522) | - | (41,481,126) | (4,912,218) | (55,062) | - | - | (210,115) | - | - |
| | Customer Service Deposits | - | - | - | - | - | - | - | - | - | - |
| | Misc. Rate Base Deductions | (433,111,498) | (429,197,632) | (445,461) | (2,741,104) | (21,881) | - | (417,563) | (135,607) | (152,252) | - |
| | Total Rate Base Deductions | (5,449,116,517) | (3,281,184,369) | (790,506,049) | (1,253,439,377) | (15,534,083) | - | (32,522,878) | (52,551,088) | (23,378,672) | - |
| Total Rate Base | | 5,269,659,203 | 1,062,637,508 | 2,279,610,271 | 1,777,400,558 | 17,509,642 | - | 27,901,730 | 94,154,513 | 10,444,981 | 0 |
| Return on Rate Base | | 6.0213% | 6.0213% | 6.0213% | 6.0213% | 6.0213% | 6.0213% | 6.0213% | 6.0213% | 6.0213% | 0.0000% |
| Return on Equity | | 6.7623% | 6.7623% | 6.7623% | 6.7623% | 6.7623% | 6.7623% | 6.7623% | 6.7623% | 6.7623% | 0.0000% |

RESULTS OF OPERATIONS SUMMARY
2020 PROTOCOL

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sales to Ultimate Customers | | | | | | | | | | | | | |
| 440 | Residential Sales | | | | | | | | | | | | |
| | | | S | 804,392,320 | 920,460,117 | 269,569,194 | 414,037,527 | 3,220,146 | 24,138,546 | 23,504,891 | 17,013,678 | 8,993,240 | 0 |
| | Less Klamath Surcharge Revenue | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | | | 804,392,320 | 920,460,117 | 269,569,194 | 414,037,527 | 3,220,146 | 24,138,546 | 23,504,891 | 17,013,678 | 8,993,240 | 0 |
| 442 | Commercial & Industrial Sales | | | | | | | | | | | | |
| | | | S | 872,999,594 | | | | | | | | | |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | PT | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 872,999,594 | - | - | - | - | - | - | - | - | - |
| 444 | Public Street & Highway Lighting | | | | | | | | | | | | |
| | | | S | 3,545,424 | | | | | | | | | |
| | | | SO | - | | | | | | | | | |
| | | | | 3,545,424 | - | - | - | - | - | - | - | - | - |
| 445 | Other Sales to Public Authority | | | | | | | | | | | | |
| | | | S | - | | | | | | | | | |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 448 | Interdepartmental | | | | | | | | | | | | |
| | | D_SPLIT | S | - | - | - | - | - | - | - | - | - | - |
| | | GP | SO | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| **Total Sales to Ultimate Customers** | | | | **1,680,937,338** | **920,460,117** | **269,569,194** | **414,037,527** | **3,220,146** | **24,138,546** | **23,504,891** | **17,013,678** | **8,993,240** | **0** |
| 447 | Sales for Resale-Non NPC | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 447NPC | Sales for Resale-NPC | | | | | | | | | | | | |
| | | P | SG | 88,412,673 | 88,412,673 | - | - | - | - | - | - | - | - |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 88,412,673 | 88,412,673 | - | - | - | - | - | - | - | - |
| | Total Sales for Resale | | | 88,412,673 | 88,412,673 | - | - | - | - | - | - | - | - |
| 449 | Provision for Rate Refund | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | - | - | - | - | - | - | - | - | - | - |
| **Total Sales from Electricity** | | | | **1,769,350,010** | **1,008,872,789** | **269,569,194** | **414,037,527** | **3,220,146** | **24,138,546** | **23,504,891** | **17,013,678** | **8,993,240** | **0** |
| 450 | Forfeited Discounts & Interest | | | | | | | | | | | | |
| | | C_BILLING | S | 5,583,122 | - | - | - | - | - | 5,583,122 | - | - | - |
| | | C_BILLING | SO | - | - | - | - | - | - | - | - | - | - |
| | | | | 5,583,122 | - | - | - | - | - | 5,583,122 | - | - | - |
| 451 | Misc Electric Revenue | | | | | | | | | | | | |
| | | CSS_SYS | S | 1,520,715 | - | - | - | - | - | 674,184 | 354,833 | 491,698 | - |
| | | C_METER | S | - | - | - | - | - | - | - | - | - | - |
| | | GP | SG | - | - | - | - | - | - | - | - | - | - |
| | | DSM | SO | - | - | - | - | - | - | - | - | - | - |
| | | | | 1,520,715 | - | - | - | - | - | 674,184 | 354,833 | 491,698 | - |
| 453 | Water Sales | | | | | | | | | | | | |
| | | P | SG | 1,339 | 1,339 | - | - | - | - | - | - | - | - |
| | | | | 1,339 | 1,339 | - | - | - | - | - | - | - | - |
| 454 | Rent of Electric Property | | | | | | | | | | | | |
| | | D | S | 5,282,389 | - | - | 5,282,389 | - | - | - | - | - | - |
| | | T | SG | 993,883 | - | 993,883 | - | - | - | - | - | - | - |
| | | GP | SO | 922,589 | 363,448 | 271,645 | 263,907 | 2,917 | - | 4,971 | 12,835 | 2,867 | - |
| | | | | 7,198,861 | 363,448 | 1,265,528 | 5,546,296 | 2,917 | - | 4,971 | 12,835 | 2,867 | - |
| | Oregon Ancillary Services | | | | 24,138,546 | | | | (24,138,546) | | | | |
| 456 | Other Electric Revenue | | | | | | | | | | | | |
| | | OTHSGR | S | - | - | - | - | - | - | - | - | - | - |
| | | C_BILLING | CN | - | - | - | - | - | - | - | - | - | - |
| | | OTHSE | SE | 9,890,899 | - | 9,890,899 | - | - | - | - | - | - | - |
| | | OTHSO | SO | 27,369 | - | - | 27,369 | - | - | - | - | - | - |
| | | OTHSGR | SG | 47,450,695 | 7,203,476 | 40,245,346 | 1,873 | - | - | - | - | - | - |
| | | | | 57,368,962 | 7,203,476 | 50,136,245 | 29,241 | - | - | - | - | - | - |
| | **Total Other Electric Revenues** | | | **71,672,999** | **31,706,809** | **51,401,773** | **5,575,537** | **2,917** | **(24,138,546)** | **6,262,277** | **367,668** | **494,564** | **-** |
| **Total Electric Operating Revenues** | | | | **1,841,023,010** | **1,040,579,598** | **320,970,967** | **419,613,065** | **3,223,063** | **-** | **29,767,167** | **17,381,346** | **9,487,804** | **0** |
| Miscellaneous Revenues | | | | | | | | | | | | | |
| 41160 | Gain on Sale of Utility Plant - CR | | | | | | | | | | | | |
| | | D | S | - | - | - | - | - | - | - | - | - | - |
| | | T | SG | - | - | - | - | - | - | - | - | - | - |
| | | G | SO | - | - | - | - | - | - | - | - | - | - |
| | | T | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 41170 | Loss on Sale of Utility Plant | | | | | | | | | | | | |
| | | D_SPLIT | S | - | - | - | - | - | - | - | - | - | - |
| | | T | SG | - | - | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | - | - | - | - | - | - | - | - | - | - |
| 4118 | Gain from Emission Allowances | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | (24) | (24) | - | - | - | - | - | - | - | - |
| | | | | (24) | (24) | - | - | - | - | - | - | - | - |
| 41181 | Gain from Disposition of NOX Credits | | | | | | | | | | | | |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 4194 | Impact Housing Interest Income | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 421 | (Gain) / Loss on Sale of Utility Plant | | | | | | | | | | | | |
| | | D | S | 80,879 | - | - | 80,879 | - | - | - | - | - | - |
| | | T | SG | - | - | - | - | - | - | - | - | - | - |
| | | T | SG | - | - | - | - | - | - | - | - | - | - |
| | | B_Center | CN | - | - | - | - | - | - | - | - | - | - |
| | | PTD | SO | (30,170) | (12,078) | (9,553) | (8,539) | - | - | - | - | - | - |
| | | P | SG | (80,690) | (80,690) | - | - | - | - | - | - | - | - |
| | | | | (29,982) | (92,768) | (9,553) | 72,340 | - | - | - | - | - | - |
| **Total Miscellaneous Revenues** | | | | **(30,006)** | **(92,792)** | **(9,553)** | **72,340** | **-** | **-** | **-** | **-** | **-** | **-** |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Miscellaneous Expenses | | | | | | | | | | | | | |
| 4311 | Interest on Customer Deposits | | | | | | | | | | | | |
| | | C_BILLING | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| **Total Miscellaneous Expenses** | | | | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| **Net Misc Revenue and Expense** | | | | **(30,006)** | **(92,792)** | **(9,553)** | **72,340** | **-** | **-** | **-** | **-** | **-** | **-** |
| 500 | Operation Supervision & Engineering | | | | | | | | | | | | |
| | | P | SG | 4,141,202 | 4,141,202 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | (4,649) | (4,649) | - | - | - | - | - | - | - | - |
| | | | | 4,136,553 | 4,136,553 | - | - | - | - | - | - | - | - |
| 501 | Fuel Related-Non NPC | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | 9,949,333 | 9,949,333 | - | - | - | - | - | - | - | - |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | | | 9,949,333 | 9,949,333 | - | - | - | - | - | - | - | - |
| 501NPC | Fuel Related-NPC | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | 186,798,767 | 186,798,767 | - | - | - | - | - | - | - | - |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | | | 186,798,767 | 186,798,767 | - | - | - | - | - | - | - | - |
| | Total Fuel Related | | | 196,748,100 | 196,748,100 | - | - | - | - | - | - | - | - |
| 502 | Steam Expenses | | | | | | | | | | | | |
| | | P | SG | 22,102,440 | 22,102,440 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | (1,366) | (1,366) | - | - | - | - | - | - | - | - |
| | | | | 22,101,075 | 22,101,075 | - | - | - | - | - | - | - | - |
| 503 | Steam From Other Sources-Non-NPC | | | | | | | | | | | | |
| | | P | SE | 142 | 142 | - | - | - | - | - | - | - | - |
| | | | | 142 | 142 | - | - | - | - | - | - | - | - |
| 503NPC | Steam From Other Sources-NPC | | | | | | | | | | | | |
| | | P | SE | 1,426,328 | 1,426,328 | - | - | - | - | - | - | - | - |
| | | | | 1,426,328 | 1,426,328 | - | - | - | - | - | - | - | - |
| 505 | Electric Expenses | | | | | | | | | | | | |
| | | P | SG | 202,383 | 202,383 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 202,383 | 202,383 | - | - | - | - | - | - | - | - |

| | FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 506 | | Misc. Steam Expense | | | | | | | | | | | | |
| | | | P | SG | 10,085,928 | 10,085,928 | - | - | - | - | - | - | - | - |
| | | | P | SG | (1,856,365) | (1,856,365) | - | - | - | - | - | - | - | - |
| | | | P | SE | 1,385,726 | 1,385,726 | - | - | - | - | - | - | - | - |
| | | | | | 9,615,289 | 9,615,289 | - | - | - | - | - | - | - | - |
| 507 | | Rents | | | | | | | | | | | | |
| | | | P | SG | (60,681) | (60,681) | - | - | - | - | - | - | - | - |
| | | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | | (60,681) | (60,681) | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 510 | Maint Supervision & Engineering | | | | | | | | | | | | |
| | | P | SG | 1,400,321 | 1,400,321 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 536,941 | 536,941 | - | - | - | - | - | - | - | - |
| | | | | 1,937,261 | 1,937,261 | - | - | - | - | - | - | - | - |
| 511 | Maintenance of Structures | | | | | | | | | | | | |
| | | P | SG | 6,203,080 | 6,203,080 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | (3,458) | (3,458) | - | - | - | - | - | - | - | - |
| | | | | 6,199,622 | 6,199,622 | - | - | - | - | - | - | - | - |
| 512 | Maintenance of Boiler Plant | | | | | | | | | | | | |
| | | P | SG | 23,598,325 | 23,598,325 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | (2,978,067) | (2,978,067) | - | - | - | - | - | - | - | - |
| | | | | 20,620,258 | 20,620,258 | - | - | - | - | - | - | - | - |
| 513 | Maintenance of Electric Plant | | | | | | | | | | | | |
| | | P | SG | 10,062,191 | 10,062,191 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | (51) | (51) | - | - | - | - | - | - | - | - |
| | | | | 10,062,140 | 10,062,140 | - | - | - | - | - | - | - | - |
| 514 | Maintenance of Misc. Steam Plant | | | | | | | | | | | | |
| | | P | SG | 3,907,462 | 3,907,462 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | (2,041) | (2,041) | - | - | - | - | - | - | - | - |
| | | | | 3,905,422 | 3,905,422 | - | - | - | - | - | - | - | - |
| **Total Steam Power Generation** | | | | **276,893,892** | **276,893,892** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| 517 | Operation Super & Engineering | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 518 | Nuclear Fuel Expense | | | | | | | | | | | | |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 519 | Coolants and Water | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 520 | Steam Expenses | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 523 | Electric Expenses | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | - | - | - | - | - | - | - | - | - | - |
| 524 | Misc. Nuclear Expenses | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 528 | Maintenance Super & Engineering | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 529 | Maintenance of Structures | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 530 | Maintenance of Reactor Plant | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 531 | Maintenance of Electric Plant | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 532 | Maintenance of Misc Nuclear | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| **Total Nuclear Power Generation** | | | | - | - | - | - | - | - | - | - | - | - |
| 535 | Operation Super & Engineering | | | | | | | | | | | | |
| | | P | SG | 256,704 | 256,704 | - | - | - | - | - | - | - | - |
| | | P | SG | (1,825) | (1,825) | - | - | - | - | - | - | - | - |
| | | P | SG | (573,977) | (573,977) | - | - | - | - | - | - | - | - |
| | | P | SG | 2,527,498 | 2,527,498 | - | - | - | - | - | - | - | - |
| | | P | SG | 980,524 | 980,524 | - | - | - | - | - | - | - | - |
| | | | | 3,188,923 | 3,188,923 | - | - | - | - | - | - | - | - |
| 536 | Water For Power | | | | | | | | | | | | |
| | | P | DGP | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | (53) | (53) | - | - | - | - | - | - | - | - |
| | | P | SG | 127,767 | 127,767 | - | - | - | - | - | - | - | - |
| | | | | 127,714 | 127,714 | - | - | - | - | - | - | - | - |
| 537 | Hydraulic Expenses | | | | | | | | | | | | |
| | | P | SG | (138) | (138) | - | - | - | - | - | - | - | - |
| | | P | SG | 1,132,780 | 1,132,780 | - | - | - | - | - | - | - | - |
| | | P | SG | 93,455 | 93,455 | - | - | - | - | - | - | - | - |
| | | P | SG | (41) | (41) | - | - | - | - | - | - | - | - |
| | | | | 1,226,056 | 1,226,056 | - | - | - | - | - | - | - | - |
| 538 | Electric Expenses | | | | | | | | | | | | |
| | | P | DGP | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 539 | Misc. Hydro Expenses | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 4,138,397 | 4,138,397 | - | - | - | - | - | - | - | - |
| | | P | SG | 2,226,342 | 2,226,342 | - | - | - | - | - | - | - | - |
| | | P | SG | (4,701) | (4,701) | - | - | - | - | - | - | - | - |
| | | P | SG | (2,257) | (2,257) | - | - | - | - | - | - | - | - |
| | | | | 6,357,780 | 6,357,780 | - | - | - | - | - | - | - | - |

| | FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 540 | | Rents (Hydro Generation) | | | | | | | | | | | | |
| | | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | P | SG | 481,295 | 481,295 | - | - | - | - | - | - | - | - |
| | | | P | SG | (36,500) | (36,500) | - | - | - | - | - | - | - | - |
| | | | | | 444,795 | 444,795 | - | - | - | - | - | - | - | - |
| 541 | | Maint Supervision & Engineering | | | | | | | | | | | | |
| | | | P | DGP | - | - | - | - | - | - | - | - | - | - |
| | | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | P | SG | 418 | 418 | - | - | - | - | - | - | - | - |
| | | | | | 418 | 418 | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 542 | Maintenance of Structures | | | | | | | | | | | | |
| | | P | SG | (23) | (23) | - | - | - | - | - | - | - | - |
| | | P | SG | 200,865 | 200,865 | - | - | - | - | - | - | - | - |
| | | P | SG | 6,017 | 6,017 | - | - | - | - | - | - | - | - |
| | | P | SG | (8) | (8) | - | - | - | - | - | - | - | - |
| | | | | 206,851 | 206,851 | - | - | - | - | - | - | - | - |
| 543 | Maintenance of Dams & Waterways | | | | | | | | | | | | |
| | | P | SG | (12) | (12) | - | - | - | - | - | - | - | - |
| | | P | SG | 256,782 | 256,782 | - | - | - | - | - | - | - | - |
| | | P | SG | 139,945 | 139,945 | - | - | - | - | - | - | - | - |
| | | P | SG | 40 | 40 | - | - | - | - | - | - | - | - |
| | | | | 396,754 | 396,754 | - | - | - | - | - | - | - | - |
| 544 | Maintenance of Electric Plant | | | | | | | | | | | | |
| | | P | SG | (73) | (73) | - | - | - | - | - | - | - | - |
| | | P | SG | 401,308 | 401,308 | - | - | - | - | - | - | - | - |
| | | P | SG | 95,824 | 95,824 | - | - | - | - | - | - | - | - |
| | | | | 497,059 | 497,059 | - | - | - | - | - | - | - | - |
| 545 | Maintenance of Misc. Hydro Plant | | | | | | | | | | | | |
| | | P | SG | 912 | 912 | - | - | - | - | - | - | - | - |
| | | P | SG | (40) | (40) | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 898,429 | 898,429 | - | - | - | - | - | - | - | - |
| | | P | SG | 248,456 | 248,456 | - | - | - | - | - | - | - | - |
| | | | | 1,147,758 | 1,147,758 | - | - | - | - | - | - | - | - |
| **Total Hydraulic Power Generation** | | | | **13,594,108** | **13,594,108** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| 546 | Operation Super & Engineering | | | | | | | | | | | | |
| | | P | SG | 141,636 | 141,636 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | (263) | (263) | - | - | - | - | - | - | - | - |
| | | | | 141,374 | 141,374 | - | - | - | - | - | - | - | - |
| 547 | Fuel-Non-NPC | | | | | | | | | | | | |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 547NPC | Fuel-NPC | | | | | | | | | | | | |
| | | P | SE | 149,606,122 | 149,606,122 | - | - | - | - | - | - | - | - |
| | | P | SE | 165,441 | 165,441 | - | - | - | - | - | - | - | - |
| | | | | 149,771,563 | 149,771,563 | - | - | - | - | - | - | - | - |
| 548 | Generation Expense | | | | | | | | | | | | |
| | | P | SG | 6,396,846 | 6,396,846 | - | - | - | - | - | - | - | - |
| | | P | SG | 248,397 | 248,397 | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | P | SG | (468) | (468) | - | - | - | - | - | - | - | - |
| | | | | 6,644,776 | 6,644,776 | - | - | - | - | - | - | - | - |
| 549 | Miscellaneous Other | | | | | | | | | | | | |
| | | P | S | 34,403 | 34,403 | - | - | - | - | - | - | - | - |
| | | P | SG | 1,166,920 | 1,166,920 | - | - | - | - | - | - | - | - |
| | | P | SG | 1,848,315 | 1,848,315 | - | - | - | - | - | - | - | - |
| | | P | SG | 1,188,914 | 1,188,914 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 4,238,552 | 4,238,552 | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 550 | Maint Supervision & Engineering | | | | | | | | | | | | |
| | | P | S | 390,750 | 390,750 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 11,190 | 11,190 | - | - | - | - | - | - | - | - |
| | | P | SG | 2,985,382 | 2,985,382 | - | - | - | - | - | - | - | - |
| | | | | 3,387,322 | 3,387,322 | - | - | - | - | - | - | - | - |
| 551 | Maint Supervision & Engineering | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 552 | Maintenance of Structures | | | | | | | | | | | | |
| | | P | SG | 665,317 | 665,317 | - | - | - | - | - | - | - | - |
| | | P | SG | 32,708 | 32,708 | - | - | - | - | - | - | - | - |
| | | P | SG | (274) | (274) | - | - | - | - | - | - | - | - |
| | | | | 697,751 | 697,751 | - | - | - | - | - | - | - | - |
| 553 | Maint of Generation & Electric Plant | | | | | | | | | | | | |
| | | P | SG | 925,929 | 925,929 | - | - | - | - | - | - | - | - |
| | | P | SG | 5,014,495 | 5,014,495 | - | - | - | - | - | - | - | - |
| | | P | SG | 81,155 | 81,155 | - | - | - | - | - | - | - | - |
| | | P | SG | 473,186 | 473,186 | - | - | - | - | - | - | - | - |
| | | | | 6,494,765 | 6,494,765 | - | - | - | - | - | - | - | - |
| 554 | Maintenance of Misc. Other | | | | | | | | | | | | |
| | | P | SG | 605,853 | 605,853 | - | - | - | - | - | - | - | - |
| | | P | SG | 488,078 | 488,078 | - | - | - | - | - | - | - | - |
| | | P | SG | 35,844 | 35,844 | - | - | - | - | - | - | - | - |
| | | P | SG | (25) | (25) | - | - | - | - | - | - | - | - |
| | | | | 1,129,749 | 1,129,749 | - | - | - | - | - | - | - | - |
| **Total Other Power Generation** | | | | **172,505,852** | **172,505,852** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| 555 | Purchased Power-Non NPC | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 555NPC | Purchased Power-NPC | | | | | | | | | | | | |
| | | P | S | (14,043,485) | (14,043,485) | - | - | - | - | - | - | - | - |
| | | P | SG | 360,318,420 | 360,318,420 | - | - | - | - | - | - | - | - |
| | | P | SE | 21,070,102 | 21,070,102 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | DGP | - | - | - | - | - | - | - | - | - | - |
| | | | | 367,345,037 | 367,345,037 | - | - | - | - | - | - | - | - |
| | Total Purchased Power | | | 367,345,037 | 367,345,037 | - | - | - | - | - | - | - | - |
| 556 | System Control & Load Dispatch | | | | | | | | | | | | |
| | | P | SG | 704,737 | 704,737 | - | - | - | - | - | - | - | - |
| | | | | 704,737 | 704,737 | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 557 | Other Expenses | | | | | | | | | | | | |
| | | P | S | 8,126,293 | 8,126,293 | - | - | - | - | - | - | - | - |
| | | P | SG | 9,802,138 | 9,802,138 | - | - | - | - | - | - | - | - |
| | | P | SGCT | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | 1,693 | 1,693 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | TROJP | - | - | - | - | - | - | - | - | - | - |
| | | | | 17,930,124 | 17,930,124 | - | - | - | - | - | - | - | - |
| | 2017 Protocol Adjustment | | | | | | | | | | | | |
| | Baseline ECD | P | S | (11,000,000) | (11,000,000) | - | - | - | - | - | - | - | - |
| | Equalization Adj. | P | S | - | - | - | - | - | - | - | - | - | - |
| | | | | (11,000,000) | (11,000,000) | - | - | - | - | - | - | - | - |
| | **Total Other Power Supply** | | | **374,979,897** | **374,979,897** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **TOTAL PRODUCTION EXPENSE** | | | **837,973,749** | **837,973,749** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| | Embedded Cost Differentials | | | | | | | | | | | | |
| | Company Owne | P | DGP | - | - | - | - | - | - | - | - | - | - |
| | Company Owne | P | SG | - | - | - | - | - | - | - | - | - | - |
| | Mid-C Contract | P | MC | - | - | - | - | - | - | - | - | - | - |
| | Mid-C Contract | P | SG | - | - | - | - | - | - | - | - | - | - |
| | Existing QF Con | P | S | - | - | - | - | - | - | - | - | - | - |
| | Existing QF Con | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| | Hydro Endowment Fixed Dollar Proposal | | | | | | | | | | | | |
| | Klamath Surcharge | P | S | - | - | - | - | - | - | - | - | - | - |
| | ECD Hydro | P | S | - | - | - | - | - | - | - | - | - | - |
| | Mid-C Contract | P | MC | - | - | - | - | - | - | - | - | - | - |
| | Mid-C Contract | P | SG | - | - | - | - | - | - | - | - | - | - |
| | Klamath Dam Remo | P | S | - | - | - | - | - | - | - | - | - | - |
| | Less Klamath Surcharge Expense | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 560 | Operation Supervision & Engineering | | | | | | | | | | | | |
| | | T | SG | 3,089,275 | - | 3,089,275 | - | - | - | - | - | - | - |
| | | T | SG | (3,057) | - | (3,057) | - | - | - | - | - | - | - |
| | | | | 3,086,218 | - | 3,086,218 | - | - | - | - | - | - | - |
| 561 | Load Dispatching | | | | | | | | | | | | |
| | | T | SG | 5,229,977 | - | 5,229,977 | - | - | - | - | - | - | - |
| | | T | SG | (977) | - | (977) | - | - | - | - | - | - | - |
| | | | | 5,229,000 | - | 5,229,000 | - | - | - | - | - | - | - |
| 562 | Station Expense | | | | | | | | | | | | |
| | | T | SG | 1,304,260 | - | 1,304,260 | - | - | - | - | - | - | - |
| | | T | SG | (5) | - | (5) | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 1,304,255 | - | 1,304,255 | - | - | - | - | - | - | - |
| 563 | Overhead Line Expense | | | | | | | | | | | | |
| | | T | SG | 486,761 | - | 486,761 | - | - | - | - | - | - | - |
| | | T | SG | (219) | - | (219) | - | - | - | - | - | - | - |
| | | | | 486,542 | - | 486,542 | - | - | - | - | - | - | - |
| 564 | Underground Line Expense | | | | | | | | | | | | |
| | | T | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 565 | Transmission of Electricity by Others-Non NPC | | | | | | | | | | | | |
| | | T | SG | - | - | - | - | - | - | - | - | - | - |
| | | T | SE | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 565NPC | Transmission of Electricity by Others-NPC | | | | | | | | | | | | |
| | | T | SG | 48,125,247 | - | 48,125,247 | - | - | - | - | - | - | - |
| | | T | SE | 3,385,791 | - | 3,385,791 | - | - | - | - | - | - | - |
| | | | | 51,511,038 | - | 51,511,038 | - | - | - | - | - | - | - |
| | Total Transmission of Electricity by Others | | | 51,511,038 | - | 51,511,038 | - | - | - | - | - | - | - |
| 566 | Misc. Transmission Expense | | | | | | | | | | | | |
| | | T | SG | 1,071,461 | - | 1,071,461 | - | - | - | - | - | - | - |
| | | T | SG | (70) | - | (70) | - | - | - | - | - | - | - |
| | | | | 1,071,390 | - | 1,071,390 | - | - | - | - | - | - | - |
| 567 | Rents - Transmission | | | | | | | | | | | | |
| | | T | SG | 639,141 | - | 639,141 | - | - | - | - | - | - | - |
| | | T | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 639,141 | - | 639,141 | - | - | - | - | - | - | - |
| 568 | Maint Supervision & Engineering | | | | | | | | | | | | |
| | | T | SG | 369,464 | - | 369,464 | - | - | - | - | - | - | - |
| | | T | SG | (652) | - | (652) | - | - | - | - | - | - | - |
| | | | | 368,812 | - | 368,812 | - | - | - | - | - | - | - |
| 569 | Maintenance of Structures | | | | | | | | | | | | |
| | | T | SG | 1,694,522 | - | 1,694,522 | - | - | - | - | - | - | - |
| | | T | SG | (4) | - | (4) | - | - | - | - | - | - | - |
| | | | | 1,694,518 | - | 1,694,518 | - | - | - | - | - | - | - |
| 570 | Maintenance of Station Equipment | | | | | | | | | | | | |
| | | STEP_UP | SG | 3,848,228 | 248,027 | 3,600,201 | - | - | - | - | - | - | - |
| | | STEP_UP | SG | (351) | (23) | (329) | - | - | - | - | - | - | - |
| | | | | 3,847,877 | 248,005 | 3,599,872 | - | - | - | - | - | - | - |
| 571 | Maintenance of Overhead Lines | | | | | | | | | | | | |
| | | T | SG | 4,191,717 | - | 4,191,717 | - | - | - | - | - | - | - |
| | | T | SG | (2,378,575) | - | (2,378,575) | - | - | - | - | - | - | - |
| | | | | 1,813,142 | - | 1,813,142 | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 572 | Maintenance of Underground Lines | | | | | | | | | | | | |
| | | T | SG | 44,400 | - | 44,400 | - | - | - | - | - | - | - |
| | | T | SG | (24) | - | (24) | - | - | - | - | - | - | - |
| | | | | 44,376 | - | 44,376 | - | - | - | - | - | - | - |
| 573 | Maint of Misc. Transmission Plant | | | | | | | | | | | | |
| | | T | SG | 25,561 | - | 25,561 | - | - | - | - | - | - | - |
| | | T | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 25,561 | - | 25,561 | - | - | - | - | - | - | - |
| **TOTAL TRANSMISSION EXPENSE** | | | | **71,121,871** | **248,005** | **70,873,866** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| 580 | Operation Supervision & Engineering | | | | | | | | | | | | |
| | | D_SPLIT | S | 1,480,647 | - | - | 1,404,810 | 15,747 | - | - | 60,089 | - | - |
| | | D_SPLIT | SNPD | 3,791,754 | - | - | 3,597,546 | 40,326 | - | - | 153,882 | - | - |
| | | | | 5,272,401 | - | - | 5,002,357 | 56,073 | - | - | 213,971 | - | - |
| 581 | Load Dispatching | | | | | | | | | | | | |
| | | D | S | - | - | - | - | - | - | - | - | - | - |
| | | D | SNPD | 4,284,593 | - | - | 4,284,593 | - | - | - | - | - | - |
| | | | | 4,284,593 | - | - | 4,284,593 | - | - | - | - | - | - |
| 582 | Station Expense | | | | | | | | | | | | |
| | | D | S | 1,136,479 | - | - | 1,136,479 | - | - | - | - | - | - |
| | | D | SNPD | 130 | - | - | 130 | - | - | - | - | - | - |
| | | | | 1,136,609 | - | - | 1,136,609 | - | - | - | - | - | - |
| 583 | Overhead Line Expenses | | | | | | | | | | | | |
| | | D | S | 2,661,115 | - | - | 2,661,115 | - | - | - | - | - | - |
| | | D | SNPD | - | - | - | - | - | - | - | - | - | - |
| | | | | 2,661,115 | - | - | 2,661,115 | - | - | - | - | - | - |
| 584 | Underground Line Expense | | | | | | | | | | | | |
| | | D | S | - | - | - | - | - | - | - | - | - | - |
| | | D | SNPD | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 585 | Street Lighting & Signal Systems | | | | | | | | | | | | |
| | | DL | S | - | - | - | - | - | - | - | - | - | - |
| | | DL | SNPD | 74,994 | - | - | - | 74,994 | - | - | - | - | - |
| | | | | 74,994 | - | - | - | 74,994 | - | - | - | - | - |
| 586 | Meter Expenses | | | | | | | | | | | | |
| | | C_Meter | S | 1,386,311 | - | - | - | - | - | - | 1,386,311 | - | - |
| | | C_Meter | SNPD | - | - | - | - | - | - | - | - | - | - |
| | | | | 1,386,311 | - | - | - | - | - | - | 1,386,311 | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 587 | Customer Installation Expenses | | | | | | | | | | | | |
| | | D | S | 7,555,742 | - | - | 7,555,742 | - | - | - | - | - | - |
| | | D | SNPD | - | - | - | - | - | - | - | - | - | - |
| | | | | 7,555,742 | - | - | 7,555,742 | - | - | - | - | - | - |
| 588 | Misc. Distribution Expenses | | | | | | | | | | | | |
| | | D | S | (297,241) | - | - | (297,241) | - | - | - | - | - | - |
| | | D | SNPD | 174,187 | - | - | 174,187 | - | - | - | - | - | - |
| | | | | (123,054) | - | - | (123,054) | - | - | - | - | - | - |
| 589 | Rents | | | | | | | | | | | | |
| | | D | S | 1,871,306 | - | - | 1,871,306 | - | - | - | - | - | - |
| | | D | SNPD | 101,222 | - | - | 101,222 | - | - | - | - | - | - |
| | | | | 1,972,528 | - | - | 1,972,528 | - | - | - | - | - | - |
| 590 | Maint Supervision & Engineering | | | | | | | | | | | | |
| | | D_SPLIT | S | 1,026,674 | - | - | 974,090 | 10,919 | - | - | 41,666 | - | - |
| | | D_SPLIT | SNPD | 831,689 | - | - | 789,091 | 8,845 | - | - | 33,753 | - | - |
| | | | | 1,858,363 | - | - | 1,763,181 | 19,764 | - | - | 75,418 | - | - |
| 591 | Maintenance of Structures | | | | | | | | | | | | |
| | | D | S | 658,957 | - | - | 658,957 | - | - | - | - | - | - |
| | | D | SNPD | 20,034 | - | - | 20,034 | - | - | - | - | - | - |
| | | | | 678,992 | - | - | 678,992 | - | - | - | - | - | - |
| 592 | Maintenance of Station Equipment | | | | | | | | | | | | |
| | | D | S | 4,194,210 | - | - | 4,194,210 | - | - | - | - | - | - |
| | | D | SNPD | 288,919 | - | - | 288,919 | - | - | - | - | - | - |
| | | | | 4,483,129 | - | - | 4,483,129 | - | - | - | - | - | - |
| 593 | Maintenance of Overhead Lines | | | | | | | | | | | | |
| | | D | S | 70,253,525 | - | - | 70,253,525 | - | - | - | - | - | - |
| | | D | SNPD | 841,112 | - | - | 841,112 | - | - | - | - | - | - |
| | | | | 71,094,637 | - | - | 71,094,637 | - | - | - | - | - | - |
| 594 | Maintenance of Underground Lines | | | | | | | | | | | | |
| | | D | S | 9,437,390 | - | - | 9,437,390 | - | - | - | - | - | - |
| | | D | SNPD | 2,418 | - | - | 2,418 | - | - | - | - | - | - |
| | | | | 9,439,809 | - | - | 9,439,809 | - | - | - | - | - | - |
| 595 | Maintenance of Line Transformers | | | | | | | | | | | | |
| | | D | S | - | - | - | - | - | - | - | - | - | - |
| | | D | SNPD | 271,777 | - | - | 271,777 | - | - | - | - | - | - |
| | | | | 271,777 | - | - | 271,777 | - | - | - | - | - | - |
| 596 | Maint of Street Lighting & Signal Sys. | | | | | | | | | | | | |
| | | DL | S | 789,399 | - | - | - | 789,399 | - | - | - | - | - |
| | | DL | SNPD | - | - | - | - | - | - | - | - | - | - |
| | | | | 789,399 | - | - | - | 789,399 | - | - | - | - | - |
| 597 | Maintenance of Meters | | | | | | | | | | | | |
| | | C_Meter | S | 178,248 | - | - | - | - | - | - | 178,248 | - | - |
| | | C_Meter | SNPD | (6,489) | - | - | - | - | - | - | (6,489) | - | - |
| | | | | 171,760 | - | - | - | - | - | - | 171,760 | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 598 | Maint of Misc. Distribution Plant | | | | | | | | | | | | |
| | | D | S | 667,194 | - | - | 667,194 | - | - | - | - | - | - |
| | | D | SNPD | 865,957 | - | - | 865,957 | - | - | - | - | - | - |
| | | | | 1,533,150 | - | - | 1,533,150 | - | - | - | - | - | - |
| **TOTAL DISTRIBUTION EXPENSE** | | | | **114,542,254** | **-** | **-** | **111,754,564** | **940,230** | **-** | **-** | **1,847,460** | **-** | **-** |
| 901 | Supervision | | | | | | | | | | | | |
| | | CUST901 | S | - | - | - | - | - | - | - | - | - | - |
| | | CUST901 | CN | 957,316 | - | - | - | - | - | 565,603 | 358,143 | 33,570 | - |
| | | | | 957,316 | - | - | - | - | - | 565,603 | 358,143 | 33,570 | - |
| 902 | Meter Reading Expense | | | | | | | | | | | | |
| | | C_Meter | S | 2,090,906 | - | - | - | - | - | - | 2,090,906 | - | - |
| | | C_Meter | CN | 234,571 | - | - | - | - | - | - | 234,571 | - | - |
| | | | | 2,325,477 | - | - | - | - | - | - | 2,325,477 | - | - |
| 903 | Customer Receipts & Collections | | | | | | | | | | | | |
| | | CUST903 | S | 2,180,645 | - | - | - | - | - | 1,657,478 | 91,571 | 431,596 | - |
| | | CUST903 | CN | 12,469,626 | - | - | - | - | - | 9,477,989 | 523,632 | 2,468,005 | - |
| | | | | 14,650,272 | - | - | - | - | - | 11,135,468 | 615,203 | 2,899,601 | - |
| 904 | Uncollectible Accounts | | | | | | | | | | | | |
| | | C_BILLING | S | 10,518,476 | - | - | - | - | - | 10,518,476 | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | C_BILLING | CN | (288,428) | - | - | - | - | - | (288,428) | - | - | - |
| | | | | 10,230,048 | - | - | - | - | - | 10,230,048 | - | - | - |
| 905 | Misc. Customer Accounts Expense | | | | | | | | | | | | |
| | | CUST905 | S | (0) | - | - | - | - | - | - | (0) | (0) | - |
| | | CUST905 | CN | 47 | - | - | - | - | - | - | 30 | 18 | - |
| | | | | 47 | - | - | - | - | - | - | 30 | 18 | - |
| **TOTAL CUSTOMER ACCOUNTS EXPENSE** | | | | **28,163,160** | **-** | **-** | **-** | **-** | **-** | **21,931,119** | **3,298,853** | **2,933,188** | **-** |
| 907 | Supervision | | | | | | | | | | | | |
| | | C_Service | S | - | - | - | - | - | - | - | - | - | - |
| | | C_Service | CN | 395 | - | - | - | - | - | - | - | 395 | - |
| | | | | 395 | - | - | - | - | - | - | - | 395 | - |
| 908 | Customer Assistance | | | | | | | | | | | | |
| | | DSM | S | 2,475,650 | - | - | 2,475,650 | - | - | - | - | - | - |
| | | C_Service | CN | 1,032,456 | - | - | - | - | - | - | - | 1,032,456 | - |
| | | | | 3,508,106 | - | - | 2,475,650 | - | - | - | - | 1,032,456 | - |
| 909 | Informational & Instructional Adv | | | | | | | | | | | | |
| | | C_Service | S | 816,425 | - | - | - | - | - | - | - | 816,425 | - |
| | | C_Service | CN | 971,524 | - | - | - | - | - | - | - | 971,524 | - |
| | | | | 1,787,949 | - | - | - | - | - | - | - | 1,787,949 | - |
| 910 | Misc. Customer Service | | | | | | | | | | | | |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | C_Service | S | - | - | - | - | - | - | - | - | - | - |
| | | C_Service | CN | 2,396 | - | - | - | - | - | - | - | 2,396 | - |
| | | | | 2,396 | - | - | - | - | - | - | - | 2,396 | - |
| **TOTAL CUSTOMER SERVICE EXPENSE** | | | | **5,298,846** | **-** | **-** | **2,475,650** | **-** | **-** | **-** | **-** | **2,823,196** | **-** |
| 911 | Supervision | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | CN | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 912 | Demonstration & Selling Expense | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | CN | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 913 | Advertising Expense | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | CN | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 916 | Misc. Sales Expense | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | CN | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| **TOTAL SALES EXPENSE** | | | | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| **Total Customer Service Exp Including Sales** | | | | **5,298,846** | **-** | **-** | **2,475,650** | **-** | **-** | **-** | **-** | **2,823,196** | **-** |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 920 | Administrative & General Salaries | | | | | | | | | | | | |
| | | LABOR | S | 93,075 | 38,979 | 6,726 | 36,645 | 277 | - | 6,305 | 1,845 | 2,299 | - |
| | | LABOR | CN | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SO | 23,417,636 | 9,807,083 | 1,692,241 | 9,219,812 | 69,747 | - | 1,586,260 | 464,112 | 578,382 | - |
| | | | | 23,510,712 | 9,846,062 | 1,698,967 | 9,256,457 | 70,024 | - | 1,592,565 | 465,956 | 580,681 | - |
| 921 | Office Supplies & expenses | | | | | | | | | | | | |
| | | LABOR | S | (4,585) | (1,920) | (331) | (1,805) | (14) | - | (311) | (91) | (113) | - |
| | | LABOR | CN | 40,807 | 17,089 | 2,949 | 16,066 | 122 | - | 2,764 | 809 | 1,008 | - |
| | | LABOR | SO | 5,065,266 | 2,121,285 | 366,034 | 1,994,258 | 15,086 | - | 343,110 | 100,388 | 125,105 | - |
| | | | | 5,101,488 | 2,136,454 | 368,652 | 2,008,519 | 15,194 | - | 345,564 | 101,106 | 125,999 | - |
| 922 | Office Supplies & expenses | | | | | | | | | | | | |
| | | LABOR | S | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | CN | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SO | (14,004,026) | (5,864,753) | (1,011,980) | (5,513,558) | (41,710) | - | (948,603) | (277,544) | (345,879) | - |
| | | | | (14,004,026) | (5,864,753) | (1,011,980) | (5,513,558) | (41,710) | - | (948,603) | (277,544) | (345,879) | - |
| 923 | Outside Services | | | | | | | | | | | | |
| | | LABOR | S | 865,859 | 362,614 | 62,570 | 340,899 | 2,579 | - | 58,651 | 17,160 | 21,385 | - |
| | | LABOR | CN | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SO | 14,315,682 | 5,995,271 | 1,034,502 | 5,636,260 | 42,638 | - | 969,713 | 283,721 | 353,577 | - |
| | | | | 15,181,541 | 6,357,885 | 1,097,072 | 5,977,160 | 45,217 | - | 1,028,365 | 300,881 | 374,962 | - |
| 924 | Property Insurance | | | | | | | | | | | | |
| | | DPW | S | 15,773,778 | - | - | 15,323,606 | - | - | - | 450,173 | - | - |
| | | PT | SG | - | - | - | - | - | - | - | - | - | - |
| | | GP | SO | 1,317,638 | 519,075 | 387,963 | 376,910 | 4,166 | - | 7,099 | 18,331 | 4,094 | - |
| | | | | 17,091,416 | 519,075 | 387,963 | 15,700,516 | 4,166 | - | 7,099 | 468,503 | 4,094 | - |
| 925 | Injuries & Damages | | | | | | | | | | | | |
| | | DPW | S | 3,960,968 | - | - | 3,847,925 | - | - | - | 113,043 | - | - |
| | | LABOR | SO | 4,415,850 | 1,849,316 | 319,105 | 1,738,575 | 13,152 | - | 299,120 | 87,517 | 109,065 | - |
| | | | | 8,376,819 | 1,849,316 | 319,105 | 5,586,500 | 13,152 | - | 299,120 | 200,561 | 109,065 | - |
| 926 | Employee Pensions & Benefits | | | | | | | | | | | | |
| | | LABOR | S | (5,733,248) | (2,401,029) | (414,305) | (2,257,250) | (17,076) | - | (388,358) | (113,627) | (141,603) | - |
| | | LABOR | SG | 797,657 | 334,051 | 57,641 | 314,047 | 2,376 | - | 54,032 | 15,809 | 19,701 | - |
| | | LABOR | SO | 31,134,863 | 13,038,984 | 2,249,915 | 12,258,179 | 92,732 | - | 2,109,009 | 617,058 | 768,986 | - |
| | | | | 26,199,272 | 10,972,005 | 1,893,252 | 10,314,976 | 78,032 | - | 1,774,682 | 519,240 | 647,084 | - |
| 927 | Franchise Requirements | | | | | | | | | | | | |
| | | DSM | S | - | - | - | - | - | - | - | - | - | - |
| | | DSM | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 928 | Regulatory Commission Expense | | | | | | | | | | | | |
| | | D | S | 8,182,327 | - | - | 8,182,327 | - | - | - | - | - | - |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | D | SO | 475,004 | - | - | 475,004 | - | - | - | - | - | - |
| | | FERC | SG | 1,750,313 | 856,312 | 894,001 | - | - | - | - | - | - | - |
| | | | | 10,407,643 | 856,312 | 894,001 | 8,657,330 | - | - | - | - | - | - |
| 929 | Duplicate Charges | | | | | | | | | | | | |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | LABOR | S | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SO | (37,315,692) | (15,627,456) | (2,696,563) | (14,691,647) | (111,141) | - | (2,527,685) | (739,556) | (921,644) | - |
| | | | | (37,315,692) | (15,627,456) | (2,696,563) | (14,691,647) | (111,141) | - | (2,527,685) | (739,556) | (921,644) | - |
| 930 | Misc General Expenses | | | | | | | | | | | | |
| | | LABOR | S | (907,933) | (380,234) | (65,610) | (357,464) | (2,704) | - | (61,501) | (17,994) | (22,425) | - |
| | | C_SERVICE | CN | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SO | 540,113 | 226,194 | 39,030 | 212,649 | 1,609 | - | 36,586 | 10,704 | 13,340 | - |
| | | | | (367,820) | (154,040) | (26,580) | (144,815) | (1,096) | - | (24,915) | (7,290) | (9,085) | - |
| 931 | Rents | | | | | | | | | | | | |
| | | LABOR | S | 333,350 | 139,604 | 24,089 | 131,244 | 993 | - | 22,580 | 6,607 | 8,233 | - |
| | | LABOR | SO | (1,185,930) | (496,656) | (85,699) | (466,915) | (3,532) | - | (80,332) | (23,504) | (29,291) | - |
| | | | | (852,579) | (357,052) | (61,610) | (335,671) | (2,539) | - | (57,752) | (16,897) | (21,057) | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 935 | Maintenance of General Plant | | | | | | | | | | | | |
| | | G | S | 287,691 | 56,088 | 101,190 | 123,639 | - | - | 3,141 | 3,632 | - | - |
| | | B_Center | CN | 10,987 | - | - | - | - | - | 7,158 | - | 3,830 | - |
| | | G | SO | 8,137,854 | 1,586,538 | 2,862,358 | 3,497,360 | - | - | 88,853 | 102,744 | - | - |
| | | | | 8,436,532 | 1,642,626 | 2,963,549 | 3,620,999 | - | - | 99,152 | 106,377 | 3,830 | - |
| **TOTAL ADMINISTRATIVE & GEN EXPENSE** | | | | **61,765,305** | **12,176,434** | **5,825,825** | **40,436,765** | **69,300** | **-** | **1,587,593** | **1,121,337** | **548,050** | **-** |
| **TOTAL O&M EXPENSE** | | | | **1,118,865,185** | **850,398,187** | **76,699,691** | **154,666,979** | **1,009,530** | **-** | **23,518,712** | **6,267,650** | **6,304,434** | **-** |
| 403SP | Steam Depreciation | | | | | | | | | | | | |
| | | P | SG | 13,623,534 | 13,623,534 | - | - | - | - | - | - | - | - |
| | | P | SG | 10,120,999 | 10,120,999 | - | - | - | - | - | - | - | - |
| | | P | SG | 89,531,621 | 89,531,621 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 113,276,155 | 113,276,155 | - | - | - | - | - | - | - | - |
| 403NP | Nuclear Depreciation | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 403HP | Hydro Depreciation | | | | | | | | | | | | |
| | | P | SG | 4,125,749 | 4,125,749 | - | - | - | - | - | - | - | - |
| | | P | SG | 354,012 | 354,012 | - | - | - | - | - | - | - | - |
| | | P | SG | 5,553,577 | 5,553,577 | - | - | - | - | - | - | - | - |
| | | P | SG | 2,517,771 | 2,517,771 | - | - | - | - | - | - | - | - |
| | | P | SG | (3,059,099) | (3,059,099) | - | - | - | - | - | - | - | - |
| | | | | 9,492,011 | 9,492,011 | - | - | - | - | - | - | - | - |
| 403OP | Other Production Depreciation | | | | | | | | | | | | |
| | | P | S | 61,373 | 61,373 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 18,450,653 | 18,450,653 | - | - | - | - | - | - | - | - |
| | | P | SG | 1,151,516 | 1,151,516 | - | - | - | - | - | - | - | - |
| | | P | SG | 43,640,253 | 43,640,253 | - | - | - | - | - | - | - | - |
| | | | | 63,303,795 | 63,303,795 | - | - | - | - | - | - | - | - |
| 403TP | Transmission Depreciation | | | | | | | | | | | | |
| | | T_Split | S | - | - | - | - | - | - | - | - | - | - |
| | | T_Split | SG | 2,218,391 | 34,605 | 2,183,786 | - | - | - | - | - | - | - |
| | | T_Split | SG | 2,776,526 | 43,311 | 2,733,215 | - | - | - | - | - | - | - |
| | | T_Split | SG | 47,093,349 | 734,616 | 46,358,732 | - | - | - | - | - | - | - |
| | | | | 52,088,266 | 812,533 | 51,275,733 | - | - | - | - | - | - | - |
| 403 | Distribution Depreciation | | | | | | | | | | | | |
| 360 | Land & Land Rights | D | S | 105,224 | - | - | 105,224 | - | - | - | - | - | - |
| 361 | Structures | D | S | 597,644 | - | - | 597,644 | - | - | - | - | - | - |
| 362 | Station Equipment | D | S | 7,130,257 | - | - | 7,130,257 | - | - | - | - | - | - |
| 363 | Storage Battery Equ | D | S | - | - | - | - | - | - | - | - | - | - |
| 364 | Poles & Towers | D | S | 16,461,953 | - | - | 16,461,953 | - | - | - | - | - | - |
| 365 | OH Conductors | D | S | 7,035,472 | - | - | 7,035,472 | - | - | - | - | - | - |
| 366 | UG Conduit | D | S | 2,251,044 | - | - | 2,251,044 | - | - | - | - | - | - |

| FERC ACCT | | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 367 | UG Conductor | D | S | 4,997,445 | - | - | 4,997,445 | - | - | - | - | - | - |
| | 368 | Line Trans | D | S | 12,694,581 | - | - | 12,694,581 | - | - | - | - | - | - |
| | 369 | Services | D | S | 7,632,164 | - | - | 7,632,164 | - | - | - | - | - | - |
| | 370 | Meters | C_Meter | S | 1,898,629 | - | - | - | - | - | - | 1,898,629 | - | - |
| | 371 | Inst Cust Prem | DL | S | 119,651 | - | - | - | 119,651 | - | - | - | - | - |
| | 372 | Leased Property | D | S | - | - | - | - | - | - | - | - | - | - |
| | 373 | Street Lighting | DL | S | 643,654 | - | - | - | 643,654 | - | - | - | - | - |
| | | | | | 61,567,717 | - | - | 58,905,783 | 763,305 | - | - | 1,898,629 | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 403GP | General Depreciation | | | | | | | | | | | | |
| | | TD | S | 6,424,180 | - | 3,392,174 | 3,032,005 | - | - | - | - | - | - |
| | | G-DGP | SG | 1,758 | 981 | 776 | - | - | - | - | - | - | - |
| | | G-DGU | SG | 9,338 | 5,214 | 4,125 | - | - | - | - | - | - | - |
| | | P | SE | 29,716 | 29,716 | - | - | - | - | - | - | - | - |
| | | B_Center | CN | 217,934 | - | - | - | - | - | 141,972 | - | 75,962 | - |
| | | G-SG | SG | 3,022,207 | 1,202,153 | 1,820,054 | - | - | - | - | - | - | - |
| | | LABOR | SO | 7,639,251 | 3,199,245 | 552,039 | 3,007,667 | 22,753 | - | 517,466 | 151,401 | 188,678 | - |
| | | P | SG | 2,441 | 2,441 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 17,346,823 | 4,439,750 | 5,769,169 | 6,039,672 | 22,753 | - | 659,438 | 151,401 | 264,640 | - |
| 403GV0 | General Vehicles | | | | | | | | | | | | |
| | | G-SG | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 403MP | Mining Depreciation | | | | | | | | | | | | |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 403EP | Experimental Plant Depreciation | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 4031 | ARO Depreciation | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| **TOTAL DEPRECIATION EXPENSE** | | | | **317,074,767** | **191,324,243** | **57,044,902** | **64,945,455** | **786,058** | **-** | **659,438** | **2,050,031** | **264,640** | **-** |
| 404GP | Amort of LT Plant - Capital Lease Gen | | | | | | | | | | | | |
| | | TD | S | 139,579 | - | 73,702 | 65,877 | - | - | - | - | - | - |
| | | I-SG | SG | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SO | 11,344 | 4,751 | 820 | 4,466 | 34 | - | 768 | 225 | 280 | - |
| | | I-DGU | SG | - | - | - | - | - | - | - | - | - | - |
| | | B_Center | CN | - | - | - | - | - | - | - | - | - | - |
| | | I-DGP | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 150,923 | 4,751 | 74,522 | 70,343 | 34 | - | 768 | 225 | 280 | - |
| 404SP | Amort of LT Plant - Cap Lease Steam | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 404IP | Amort of LT Plant - Intangible Plant | | | | | | | | | | | | |
| | | TD | S | 11,216 | - | 5,922 | 5,294 | - | - | - | - | - | - |
| | | P | SE | 248 | 248 | - | - | - | - | - | - | - | - |
| | | I-SG | SG | 1,562,768 | 993,603 | 569,165 | - | - | - | - | - | - | - |
| | | LABOR | SO | 10,920,283 | 4,573,310 | 789,138 | 4,299,450 | 32,525 | - | 739,716 | 216,428 | 269,715 | - |
| | | CSS_SYS | CN | 4,785,713 | - | - | - | - | - | 2,121,666 | 1,116,666 | 1,547,381 | - |
| | | I-SG | SG | 720,638 | 458,179 | 262,459 | - | - | - | - | - | - | - |
| | | I-SG | SG | 84,585 | 53,779 | 30,806 | - | - | - | - | - | - | - |
| | | I-DGP | SG | 21,143 | 21,143 | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | I-SG | SG | - | - | - | - | - | - | - | - | - | - |
| | | I-SG | SG | - | - | - | - | - | - | - | - | - | - |
| | | I-DGU | SG | 3,353 | 3,353 | - | - | - | - | - | - | - | - |
| | | | | 18,109,947 | 6,103,615 | 1,657,491 | 4,304,743 | 32,525 | - | 2,861,383 | 1,333,094 | 1,817,096 | - |
| 404MP | Amort of LT Plant - Mining Plant | | | | | | | | | | | | |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 404OP | Amort of LT Plant - Other Plant | | | | | | | | | | | | |
| | | P | S | 70,641 | 70,641 | - | - | - | - | - | - | - | - |
| | | | | 70,641 | 70,641 | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 404HP | Amortization of Other Electric Plant | | | | | | | | | | | | |
| | | P | SG | 84,383 | 84,383 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 84,383 | 84,383 | - | - | - | - | - | - | - | - |
| **Total Amortization of Limited Term Plant** | | | | **18,415,894** | **6,263,390** | **1,732,013** | **4,375,086** | **32,559** | **-** | **2,862,151** | **1,333,319** | **1,817,376** | **-** |
| 405 | Amortization of Other Electric Plant | | | | | | | | | | | | |
| | | GP | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 406 | Amortization of Plant Acquisition Adj | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 20,258 | 20,258 | - | - | - | - | - | - | - | - |
| | | P | SO | - | - | - | - | - | - | - | - | - | - |
| | | | | 20,258 | 20,258 | - | - | - | - | - | - | - | - |
| 407 | Amort of Prop Losses, Unrec Plant, etc | | | | | | | | | | | | |
| | | DPW | S | 8,853,406 | - | - | 8,600,736 | - | - | - | 252,670 | - | - |
| | | GP | SO | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 519,760 | 519,760 | - | - | - | - | - | - | - | - |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | TROJP | - | - | - | - | - | - | - | - | - | - |
| | | | | 9,373,166 | 519,760 | - | 8,600,736 | - | - | - | 252,670 | - | - |
| **TOTAL AMORTIZATION EXPENSE** | | | | **27,809,318** | **6,803,407** | **1,732,013** | **12,975,823** | **32,559** | **-** | **2,862,151** | **1,585,989** | **1,817,376** | **-** |
| 408 | Taxes Other Than Income | | | | | | | | | | | | |
| | | D | S | 45,708,476 | - | - | 45,708,476 | - | - | - | - | - | - |
| | | GP | GPS | 49,277,803 | 19,412,658 | 14,509,261 | 14,095,920 | 155,799 | - | 265,508 | 685,544 | 153,113 | - |
| | | REVREQ | SO | 4,232,970 | 2,392,551 | 737,992 | 964,795 | 7,411 | - | 68,442 | 39,964 | 21,815 | 0 |
| | | P | SE | 317,499 | 317,499 | - | - | - | - | - | - | - | - |
| | | P | SG | 1,057,149 | 1,057,149 | - | - | - | - | - | - | - | - |
| | | DSM | OPRV-ID | - | - | - | - | - | - | - | - | - | - |
| | | GP | EXCTAX | - | - | - | - | - | - | - | - | - | - |
| | | GP | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 100,593,896 | 23,179,856 | 15,247,253 | 60,769,191 | 163,210 | - | 333,950 | 725,508 | 174,928 | 0 |
| 41140 | Deferred Investment Tax Credit - Fed | | | | | | | | | | | | |
| | | PTD | DGU | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 41141 | Deferred Investment Tax Credit - Idaho | | | | | | | | | | | | |
| | | PTD | DGU | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| TOTAL DEFERRED ITC | | | | - | - | - | - | - | - | - | - | - | - |
| 427 | Interest on Long-Term Debt | | | | | | | | | | | | |
| | | NP | S | 142,009,669 | 45,334,880 | 54,254,738 | 39,121,713 | 391,789 | - | 560,851 | 2,108,545 | 237,153 | - |
| | | NP | SNP | - | - | - | - | - | - | - | - | - | - |
| | | | | 142,009,669 | 45,334,880 | 54,254,738 | 39,121,713 | 391,789 | - | 560,851 | 2,108,545 | 237,153 | - |
| 428 | Amortization of Debt Disc & Exp | | | | | | | | | | | | |
| | | NP | SNP | 1,328,071 | 423,971 | 507,389 | 365,865 | 3,664 | - | 5,245 | 19,719 | 2,218 | - |
| | | | | 1,328,071 | 423,971 | 507,389 | 365,865 | 3,664 | - | 5,245 | 19,719 | 2,218 | - |
| 429 | Amortization of Premium on Debt | | | | | | | | | | | | |
| | | NP | SNP | (414) | (132) | (158) | (114) | (1) | - | (2) | (6) | (1) | - |
| | | | | (414) | (132) | (158) | (114) | (1) | - | (2) | (6) | (1) | - |
| 431 | Other Interest Expense | | | | | | | | | | | | |
| | | NUTIL | OTH | - | - | - | - | - | - | - | - | - | - |
| | | GP | SO | - | - | - | - | - | - | - | - | - | - |
| | | NP | SNP | 8,172,894 | 2,609,098 | 3,122,451 | 2,251,520 | 22,548 | - | 32,278 | 121,350 | 13,649 | - |
| | | | | 8,172,894 | 2,609,098 | 3,122,451 | 2,251,520 | 22,548 | - | 32,278 | 121,350 | 13,649 | - |
| 432 | AFUDC - Borrowed | | | | | | | | | | | | |
| | | NP | SNP | (12,419,040) | (3,964,629) | (4,744,689) | (3,421,275) | (34,263) | - | (49,048) | (184,397) | (20,740) | - |
| | | | | (12,419,040) | (3,964,629) | (4,744,689) | (3,421,275) | (34,263) | - | (49,048) | (184,397) | (20,740) | - |
| | Total Electric Interest Deductions for Tax | | | 139,091,179 | 44,403,187 | 53,139,730 | 38,317,710 | 383,737 | - | 549,325 | 2,065,212 | 232,279 | - |
| | Non-Utility Portion of Interest | | | | | | | | | | | | |
| | 427 | NUTIL | NUTIL | - | - | - | - | - | - | - | - | - | - |
| | 428 | NUTIL | NUTIL | - | - | - | - | - | - | - | - | - | - |
| | 429 | NUTIL | NUTIL | - | - | - | - | - | - | - | - | - | - |
| | 431 | NUTIL | NUTIL | - | - | - | - | - | - | - | - | - | - |
| | Total Non-utility Interest | | | - | - | - | - | - | - | - | - | - | - |
| | Total Interest Deductions for Tax | | | 139,091,179 | 44,403,187 | 53,139,730 | 38,317,710 | 383,737 | - | 549,325 | 2,065,212 | 232,279 | - |
| 419 | Interest & Dividends | | | | | | | | | | | | |
| | | GP | S | - | - | - | - | - | - | - | - | - | - |
| | | GP | SNP | (65,590,851) | (25,839,073) | (19,312,443) | (18,762,269) | (207,375) | - | (353,402) | (912,488) | (203,800) | - |
| | Total Operating Deductions for Tax | | | (65,590,851) | (25,839,073) | (19,312,443) | (18,762,269) | (207,375) | - | (353,402) | (912,488) | (203,800) | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 41010 | Deferred Income Tax - Federal-DR | | | | | | | | | | | | |
| | | GP | S | (310,307) | (122,243) | (91,366) | (88,763) | (981) | - | (1,672) | (4,317) | (964) | - |
| | | P | CHMDEX | - | - | - | - | - | - | - | - | - | - |
| | | PT | SG | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SO | (4,459,821) | (1,867,730) | (322,282) | (1,755,886) | (13,283) | - | (302,099) | (88,389) | (110,151) | - |
| | | NP | SNP | 23,454,306 | 7,487,505 | 8,960,708 | 6,461,339 | 64,708 | - | 92,630 | 348,247 | 39,168 | - |
| | | P | SE | 4,202 | 4,202 | - | - | - | - | - | - | - | - |
| | | PT | SG | 10,295,739 | 5,748,698 | 4,547,042 | - | - | - | - | - | - | - |
| | | GP | GPS | 3,147,512 | 1,239,941 | 926,747 | 900,346 | 9,951 | - | 16,959 | 43,788 | 9,780 | - |
| | | TAXDEPR | TAXDEPR | 90,338,073 | 39,348,590 | 25,471,400 | 23,527,116 | 31,559 | - | 775,675 | 682,594 | 501,139 | - |
| | | C_BILLING | BADDEBT | - | - | - | - | - | - | - | - | - | - |
| | | CSS_SYS | CN | - | - | - | - | - | - | - | - | - | - |
| | | IBT | IBT | - | - | - | - | - | - | - | - | - | - |
| | | D | SNPD | - | - | - | - | - | - | - | - | - | - |
| | | | | 122,469,704 | 51,838,962 | 39,492,249 | 29,044,152 | 91,953 | - | 581,494 | 981,923 | 438,971 | - |
| 41110 | Deferred Income Tax - Federal-CR | | | | | | | | | | | | |
| | | GP | S | (17,268,513) | (6,802,814) | (5,084,508) | (4,939,660) | (54,597) | - | (93,042) | (240,236) | (53,656) | - |
| | | P | SE | (963,569) | (963,569) | - | - | - | - | - | - | - | - |
| | | C_BILLING | BADDEBT | (0) | - | - | - | - | - | (0) | - | - | - |
| | | NP | SNP | (13,937,921) | (4,449,514) | (5,324,977) | (3,839,706) | (38,453) | - | (55,046) | (206,949) | (23,276) | - |
| | | PT | SG | - | - | - | - | - | - | - | - | - | - |
| | | D_SPLIT | CIAC | (9,236,961) | - | - | (8,763,859) | (98,237) | - | - | (374,865) | - | - |
| | | LABOR | SO | (3,053,086) | (1,278,603) | (220,627) | (1,202,037) | (9,093) | - | (206,809) | (60,509) | (75,407) | - |
| | | D | SNPD | - | - | - | - | - | - | - | - | - | - |
| | | CSS_SYS | CN | 6,702 | - | - | - | - | - | 2,971 | 1,564 | 2,167 | - |
| | | P | SGCT | - | - | - | - | - | - | - | - | - | - |
| | | BOOKDEPR | CHMDEX | (71,931,536) | (43,818,759) | (11,141,787) | (16,234,458) | (196,414) | - | (63,187) | (476,931) | - | - |
| | | P | TROJD | - | - | - | - | - | - | - | - | - | - |
| | | IBT | IBT | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | (14,634,969) | (14,634,969) | - | - | - | - | - | - | - | - |
| | | GP | GPS | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | (131,019,852) | (71,948,228) | (21,771,898) | (34,979,720) | (396,794) | - | (415,113) | (1,357,927) | (150,171) | - |
| TOTAL DEFERRED INCOME TAXES | | | | (8,550,148) | (20,109,266) | 17,720,351 | (5,935,568) | (304,841) | - | 166,380 | (376,004) | 288,800 | - |
| SCHMAF | Additions - Flow Through | | | | | | | | | | | | |
| | | SCHMAF | S | - | - | - | - | - | - | - | - | - | - |
| | | SCHMAF | SNP | - | - | - | - | - | - | - | - | - | - |
| | | SCHMAF | SO | - | - | - | - | - | - | - | - | - | - |
| | | SCHMAF | SE | - | - | - | - | - | - | - | - | - | - |
| | | P | TROJP | - | - | - | - | - | - | - | - | - | - |
| | | SCHMAF | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| SCHMAP | Additions - Permanent | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | 3,953 | 3,953 | - | - | - | - | - | - | - | - |
| | | PTD | SNP | - | - | - | - | - | - | - | - | - | - |
| | | SCHMAP-SO | SO | 520,374 | 327,647 | 23,962 | 130,553 | 988 | - | 22,462 | 6,572 | 8,190 | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | SCHMAP | SG | - | - | - | - | - | - | - | - | - | - |
| | | BOOKDEPR | CHMDEX | 35,183 | 21,432 | 5,450 | 7,941 | 96 | - | 31 | 233 | - | - |
| | | | | 559,509 | 353,033 | 29,412 | 138,494 | 1,084 | - | 22,492 | 6,805 | 8,190 | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SCHMAT | Additions - Temporary | | | | | | | | | | | | |
| | | SCHMAT-SITU | S | 21,022,362 | 12,451,718 | 2,744,882 | 4,949,803 | 20,847 | - | 474,119 | 208,121 | 172,873 | - |
| | | SCHMAT-SG | GPS | - | - | - | - | - | - | - | - | - | - |
| | | D_SPLIT | CIAC | 37,569,085 | - | - | 35,644,858 | 399,553 | - | - | 1,524,674 | - | - |
| | | SCHMAT-SNP | SNP | 56,689,096 | 25,322,437 | 15,132,853 | 15,769,087 | - | - | 674 | 463,584 | 461 | - |
| | | P | TROJD | - | - | - | - | - | - | - | - | - | - |
| | | C_BILLING | BADDEBT | 0 | - | - | - | - | - | 0 | - | - | - |
| | | SCHMAT-SE | SE | 3,919,087 | 4,019,851 | (12,528) | (68,257) | (516) | - | (11,744) | (3,436) | (4,282) | - |
| | | SCHMAT-SG | GPS | - | - | - | - | - | - | - | - | - | - |
| | | CSS_SYS | CN | (27,260) | - | - | - | - | - | (12,085) | (6,361) | (8,814) | - |
| | | SCHMAT-SO | SO | 7,835,068 | 3,279,704 | 555,415 | 3,091,159 | 23,501 | - | 534,480 | 155,927 | 194,882 | - |
| | | SCHMAT-SNP | SNPD | - | - | - | - | - | - | - | - | - | - |
| | | P | SGCT | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | BOOKDEPR | CHMDEX | 292,563,984 | 178,222,118 | 45,316,500 | 66,029,699 | 798,868 | - | 256,996 | 1,939,802 | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 11,286,610 | 11,286,610 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 430,858,032 | 234,582,438 | 63,737,122 | 125,416,349 | 1,242,252 | - | 1,242,440 | 4,282,311 | 355,120 | - |
| TOTAL SCHEDULE - M ADDITIONS | | | | 431,417,541 | 234,935,471 | 63,766,534 | 125,554,842 | 1,243,336 | - | 1,264,932 | 4,289,116 | 363,310 | - |
| SCHMDF | Deductions - Flow Through | | | | | | | | | | | | |
| | | SCHMDF | S | - | - | - | - | - | - | - | - | - | - |
| | | SCHMDF | SG | - | - | - | - | - | - | - | - | - | - |
| | | SCHMDF | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| SCHMDP | Deductions - Permanent | | | | | | | | | | | | |
| | | SCHMDP | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | 151,388 | 151,388 | - | - | - | - | - | - | - | - |
| | | SCHMDP | SNP | 28,210 | 27,722 | 235 | 245 | - | - | - | 7 | - | - |
| | | BOOKDEPR | CHMDEX | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | SCHMDP-SO | SO | - | - | - | - | - | - | - | - | - | - |
| | | | | 179,597 | 179,110 | 235 | 245 | - | - | - | 7 | - | - |
| SCHMDT | Deductions - Temporary | | | | | | | | | | | | |
| | | SCHMDT-SITU | S | (1,262,073) | (1,317,676) | 11,697 | 41,862 | 46 | - | 1,088 | 497 | 413 | - |
| | | SCHMDT | BADDEBT | - | - | - | - | - | - | - | - | - | - |
| | | SCHMDT-SNP | SNP | 95,394,668 | 42,617,032 | 25,464,097 | 26,534,030 | - | - | - | 779,509 | - | - |
| | | SCHMDT | CN | - | - | - | - | - | - | - | - | - | - |
| | | SCHMDT-SG | SG | - | - | - | - | - | - | - | - | - | - |
| | | SCHMDT-SG | SG | 41,875,413 | 43,016,005 | (1,140,592) | - | - | - | - | - | - | - |
| | | P | SE | 17,092 | 17,092 | - | - | - | - | - | - | - | - |
| | | SCHMDT-SG | SG | - | - | - | - | - | - | - | - | - | - |
| | | SCHMDT-GPS | GPS | 12,801,734 | 5,719,103 | 3,417,220 | 3,560,803 | - | - | - | 104,608 | - | - |
| | | SCHMDT-SO | SO | (18,139,232) | (7,616,209) | 311,525 | (7,657,725) | (83,908) | - | (1,906,583) | (491,711) | (694,622) | - |
| | | TAXDEPR | TAXDEPR | 367,428,084 | 160,040,796 | 103,598,708 | 95,690,808 | 128,357 | - | 3,154,871 | 2,776,286 | 2,038,259 | - |
| | | SCHMDT-SNP | SNPD | (0) | (0) | (0) | (0) | - | - | - | (0) | - | - |
| | | | | 498,115,685 | 242,476,143 | 131,662,656 | 118,169,778 | 44,494 | - | 1,249,376 | 3,169,189 | 1,344,050 | - |
| TOTAL SCHEDULE - M DEDUCTIONS | | | | 498,295,283 | 242,655,252 | 131,662,891 | 118,170,024 | 44,494 | - | 1,249,376 | 3,169,196 | 1,344,050 | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TOTAL SCHEDULE - M ADJUSTMENTS | | | | (66,877,741) | (7,719,781) | (67,896,357) | 7,384,819 | 1,198,842 | - | 15,557 | 1,119,920 | (980,740) | - |
| 40911 | State Income Taxes | | | | | | | | | | | | |
| | | REVREQ | | 6,189,463 | 3,498,397 | 1,079,095 | 1,410,726 | 10,836 | - | 100,076 | 58,436 | 31,898 | 0 |
| | | REVREQ | S | 219,094 | 123,836 | 38,198 | 49,937 | 384 | - | 3,542 | 2,068 | 1,129 | 0 |
| | PTC | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | IBT | IBT | - | - | - | - | - | - | - | - | - | - |
| **TOTAL STATE TAXES** | | | | 6,408,557 | 3,622,233 | 1,117,292 | 1,460,663 | 11,219 | - | 103,619 | 60,504 | 33,027 | 0 |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Calculation of Taxable Income: | | | | | | | | | | | | | |
| | Operating Revenues | | | 1,841,023,010 | 1,040,579,598 | 320,970,967 | 419,613,065 | 3,223,063 | - | 29,767,167 | 17,381,346 | 9,487,804 | 0 |
| | Operating Deductions: | | | | | | | | | | | | |
| | O & M Expenses | | | 1,118,865,185 | 850,398,187 | 76,699,691 | 154,666,979 | 1,009,530 | - | 23,518,712 | 6,267,650 | 6,304,434 | - |
| | Depreciation Expense | | | 317,074,767 | 191,324,243 | 57,044,902 | 64,945,455 | 786,058 | - | 659,438 | 2,050,031 | 264,640 | - |
| | Amortization Expense | | | 27,809,318 | 6,803,407 | 1,732,013 | 12,975,823 | 32,559 | - | 2,862,151 | 1,585,989 | 1,817,376 | - |
| | Taxes Other Than Income | | | 100,593,896 | 23,179,856 | 15,247,253 | 60,769,191 | 163,210 | - | 333,950 | 725,508 | 174,928 | 0 |
| | Interest & Dividends (AFUDC-Equity) | | | (65,590,851) | (25,839,073) | (19,312,443) | (18,762,269) | (207,375) | - | (353,402) | (912,488) | (203,800) | - |
| | Misc Revenue & Expense | | | (30,006) | (92,792) | (9,553) | 72,340 | - | - | - | - | - | - |
| | Total Operating Deductions | | | 1,498,722,309 | 1,045,773,829 | 131,401,862 | 274,667,518 | 1,783,981 | - | 27,020,849 | 9,716,690 | 8,357,579 | 0 |
| | Other Deductions: | | | | | | | | | | | | |
| | Interest Deductions | | | 139,091,179 | 44,403,187 | 53,139,730 | 38,317,710 | 383,737 | - | 549,325 | 2,065,212 | 232,279 | - |
| | Interest on PCRBS | | | - | - | - | - | - | - | - | - | - | - |
| | Schedule M Adjustments | | | (66,877,741) | (7,719,781) | (67,896,357) | 7,384,819 | 1,198,842 | - | 15,557 | 1,119,920 | (980,740) | - |
| | Income Before State Taxes | | | 136,331,781 | (57,317,199) | 68,533,017 | 114,012,655 | 2,254,187 | - | 2,212,550 | 6,719,364 | (82,794) | 0 |
| | State Income Taxes | | | 6,408,557 | 3,622,233 | 1,117,292 | 1,460,663 | 11,219 | - | 103,619 | 60,504 | 33,027 | 0 |
| Total Taxable Income | | | | 129,923,224 | (60,939,431) | 67,415,725 | 112,551,992 | 2,242,967 | - | 2,108,931 | 6,658,860 | (115,821) | 0 |
| Tax Rate | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Federal Income Tax - Calculated | | | | 27,283,877 | (12,797,281) | 14,157,302 | 23,635,918 | 471,023 | - | 442,876 | 1,398,361 | (24,322) | 0 |
| Adjustments to Calculated Tax: | | | | | | | | | | | | | |
| 40910 | PMI | P | SE | (3,951) | (3,951) | - | - | - | - | - | - | - | - |
| 40910 | Renewable Energy ( | P | SG | (65,720,255) | (65,720,255) | - | - | - | - | - | - | - | - |
| 40910 | | P | SO | (9,163) | (9,163) | - | - | - | - | - | - | - | - |
| 40910 | | P | S | - | - | - | - | - | - | - | - | - | - |
| Federal Income Tax | | | | (38,449,492) | (78,530,650) | 14,157,302 | 23,635,918 | 471,023 | - | 442,876 | 1,398,361 | (24,322) | 0 |
| **TOTAL OPERATING EXPENSES** | | | | **1,523,722,077** | **976,595,219** | **183,709,251** | **312,590,801** | **2,168,758** | **-** | **28,087,126** | **11,712,039** | **8,858,882** | **0** |
| 310 | Land and Land Rights | | | | | | | | | | | | |
| | | P | SG | 625,603 | 625,603 | - | - | - | - | - | - | - | - |
| | | P | SG | 9,078,654 | 9,078,654 | - | - | - | - | - | - | - | - |
| | | P | SG | 14,611,953 | 14,611,953 | - | - | - | - | - | - | - | - |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 340,582 | 340,582 | - | - | - | - | - | - | - | - |
| | | | | 24,656,792 | 24,656,792 | - | - | - | - | - | - | - | - |
| 311 | Structures and Improvements | | | | | | | | | | | | |
| | | P | SG | 60,593,953 | 60,593,953 | - | - | - | - | - | - | - | - |
| | | P | SG | 83,636,058 | 83,636,058 | - | - | - | - | - | - | - | - |
| | | P | SG | 126,777,211 | 126,777,211 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 271,007,222 | 271,007,222 | - | - | - | - | - | - | - | - |
| 312 | Boiler Plant Equipment | | | | | | | | | | | | |
| | | P | SG | 157,159,755 | 157,159,755 | - | - | - | - | - | - | - | - |
| | | P | SG | 124,342,847 | 124,342,847 | - | - | - | - | - | - | - | - |
| | | P | SG | 943,094,422 | 943,094,422 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 1,224,597,024 | 1,224,597,024 | - | - | - | - | - | - | - | - |
| 314 | Turbogenerator Units | | | | | | | | | | | | |
| | | P | SG | 29,135,609 | 29,135,609 | - | - | - | - | - | - | - | - |
| | | P | SG | 28,630,467 | 28,630,467 | - | - | - | - | - | - | - | - |
| | | P | SG | 209,310,389 | 209,310,389 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 267,076,465 | 267,076,465 | - | - | - | - | - | - | - | - |
| 315 | Accessory Electric Equipment | | | | | | | | | | | | |
| | | P | SG | 23,035,108 | 23,035,108 | - | - | - | - | - | - | - | - |
| | | P | SG | 35,774,993 | 35,774,993 | - | - | - | - | - | - | - | - |
| | | P | SG | 56,398,152 | 56,398,152 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 115,208,253 | 115,208,253 | - | - | - | - | - | - | - | - |
| 316 | Misc Power Plant Equipment | | | | | | | | | | | | |
| | | P | SG | 631,332 | 631,332 | - | - | - | - | - | - | - | - |
| | | P | SG | 1,293,918 | 1,293,918 | - | - | - | - | - | - | - | - |
| | | P | SG | 7,206,889 | 7,206,889 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 9,132,139 | 9,132,139 | - | - | - | - | - | - | - | - |
| 317 | Steam Plant ARO | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| SP | Unclassified Steam Plant - Account 300 | | | | | | | | | | | | |
| | | P | SG | 4,782,433 | 4,782,433 | - | - | - | - | - | - | - | - |
| | | | | 4,782,433 | 4,782,433 | - | - | - | - | - | - | - | - |
| **Total Steam Production Plant** | | | | **1,916,460,328** | **1,916,460,328** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| 320 | Land and Land Rights | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 321 | Structures and Improvements | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 322 | Reactor Plant Equipment | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 323 | Turbogenerator Units | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 324 | Land and Land Rights | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 325 | Misc. Power Plant Equipment | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| NP | Unclassified Nuclear Plant - Acct 300 | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| **Total Nuclear Production Plant** | | | | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| 330 | Land and Land Rights | | | | | | | | | | | | |
| | | P | SG | 2,644,542 | 2,644,542 | - | - | - | - | - | - | - | - |
| | | P | SG | 1,415,443 | 1,415,443 | - | - | - | - | - | - | - | - |
| | | P | SG | 5,924,179 | 5,924,179 | - | - | - | - | - | - | - | - |
| | | P | SG | 358,466 | 358,466 | - | - | - | - | - | - | - | - |
| | | | | 10,342,631 | 10,342,631 | - | - | - | - | - | - | - | - |
| 331 | Structures and Improvements | | | | | | | | | | | | |
| | | P | SG | 4,079,017 | 4,079,017 | - | - | - | - | - | - | - | - |
| | | P | SG | 1,277,614 | 1,277,614 | - | - | - | - | - | - | - | - |
| | | P | SG | 65,964,688 | 65,964,688 | - | - | - | - | - | - | - | - |
| | | P | SG | 4,669,579 | 4,669,579 | - | - | - | - | - | - | - | - |
| | | | | 75,990,898 | 75,990,898 | - | - | - | - | - | - | - | - |
| 332 | Reservoirs, Dams & Waterways | | | | | | | | | | | | |
| | | P | SG | 33,938,250 | 33,938,250 | - | - | - | - | - | - | - | - |
| | | P | SG | 5,019,638 | 5,019,638 | - | - | - | - | - | - | - | - |
| | | P | SG | 102,845,475 | 102,845,475 | - | - | - | - | - | - | - | - |
| | | P | SG | 31,689,163 | 31,689,163 | - | - | - | - | - | - | - | - |
| | | P | SG | (355,300) | (355,300) | - | - | - | - | - | - | - | - |
| | | | | 173,137,226 | 173,137,226 | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 333 | Water Wheel, Turbines, & Generators | | | | | | | | | | | | |
| | | P | SG | 6,855,366 | 6,855,366 | - | - | - | - | - | - | - | - |
| | | P | SG | 1,798,769 | 1,798,769 | - | - | - | - | - | - | - | - |
| | | P | SG | 14,463,480 | 14,463,480 | - | - | - | - | - | - | - | - |
| | | P | SG | 11,988,643 | 11,988,643 | - | - | - | - | - | - | - | - |
| | | | | 35,106,257 | 35,106,257 | - | - | - | - | - | - | - | - |
| 334 | Accessory Electric Equipment | | | | | | | | | | | | |
| | | P | SG | 748,052 | 748,052 | - | - | - | - | - | - | - | - |
| | | P | SG | 896,830 | 896,830 | - | - | - | - | - | - | - | - |
| | | P | SG | 14,931,325 | 14,931,325 | - | - | - | - | - | - | - | - |
| | | P | SG | 3,060,519 | 3,060,519 | - | - | - | - | - | - | - | - |
| | | | | 19,636,726 | 19,636,726 | - | - | - | - | - | - | - | - |
| 335 | Misc. Power Plant Equipment | | | | | | | | | | | | |
| | | P | SG | 261,780 | 261,780 | - | - | - | - | - | - | - | - |
| | | P | SG | 40,548 | 40,548 | - | - | - | - | - | - | - | - |
| | | P | SG | 402,544 | 402,544 | - | - | - | - | - | - | - | - |
| | | P | SG | 16,494 | 16,494 | - | - | - | - | - | - | - | - |
| | | | | 721,366 | 721,366 | - | - | - | - | - | - | - | - |
| 336 | Roads, Railroads & Bridges | | | | | | | | | | | | |
| | | P | SG | 866,152 | 866,152 | - | - | - | - | - | - | - | - |
| | | P | SG | 197,437 | 197,437 | - | - | - | - | - | - | - | - |
| | | P | SG | 4,866,411 | 4,866,411 | - | - | - | - | - | - | - | - |
| | | P | SG | 955,018 | 955,018 | - | - | - | - | - | - | - | - |
| | | | | 6,885,019 | 6,885,019 | - | - | - | - | - | - | - | - |
| 337 | Hydro Plant ARO | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| HP | Unclassified Hydro Plant - Acct 300 | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| **Total Hydraulic Plant** | | | | **321,820,122** | **321,820,122** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| 340 | Land and Land Rights | | | | | | | | | | | | |
| | | P | S | 74,986 | 74,986 | - | - | - | - | - | - | - | - |
| | | P | SG | 10,490,871 | 10,490,871 | - | - | - | - | - | - | - | - |
| | | P | SG | 3,638,315 | 3,638,315 | - | - | - | - | - | - | - | - |
| | | P | SG | 63,213 | 63,213 | - | - | - | - | - | - | - | - |
| | | | | 14,267,385 | 14,267,385 | - | - | - | - | - | - | - | - |
| 341 | Structures and Improvements | | | | | | | | | | | | |
| | | P | S | 3,756 | 3,756 | - | - | - | - | - | - | - | - |
| | | P | SG | 45,093,476 | 45,093,476 | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 27,047,066 | 27,047,066 | - | - | - | - | - | - | - | - |
| | | P | SG | 1,148,760 | 1,148,760 | - | - | - | - | - | - | - | - |
| | | | | 73,293,058 | 73,293,058 | - | - | - | - | - | - | - | - |
| 342 | Fuel Holders, Producers & Accessories | | | | | | | | | | | | |
| | | P | SG | 3,669,749 | 3,669,749 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 749,832 | 749,832 | - | - | - | - | - | - | - | - |
| | | | | 4,419,581 | 4,419,581 | - | - | - | - | - | - | - | - |
| 343 | Prime Movers | | | | | | | | | | | | |
| | | P | S | 370,052 | 370,052 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 944,618,365 | 944,618,365 | - | - | - | - | - | - | - | - |
| | | P | SG | 249,367,526 | 249,367,526 | - | - | - | - | - | - | - | - |
| | | P | SG | 16,431,589 | 16,431,589 | - | - | - | - | - | - | - | - |
| | | | | 1,210,787,532 | 1,210,787,532 | - | - | - | - | - | - | - | - |
| 344 | Generators | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 44,415,479 | 44,415,479 | - | - | - | - | - | - | - | - |
| | | P | SG | 108,382,133 | 108,382,133 | - | - | - | - | - | - | - | - |
| | | P | SG | 4,785,333 | 4,785,333 | - | - | - | - | - | - | - | - |
| | | | | 157,582,946 | 157,582,946 | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 345 | Accessory Electric Plant | | | | | | | | | | | | |
| | | P | S | 516,566 | 516,566 | - | - | - | - | - | - | - | - |
| | | P | SG | 53,612,432 | 53,612,432 | - | - | - | - | - | - | - | - |
| | | P | SG | 66,576,326 | 66,576,326 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 780,042 | 780,042 | - | - | - | - | - | - | - | - |
| | | | | 121,485,366 | 121,485,366 | - | - | - | - | - | - | - | - |
| 346 | Misc. Power Plant Equipment | | | | | | | | | | | | |
| | | P | SG | 3,311,693 | 3,311,693 | - | - | - | - | - | - | - | - |
| | | P | SG | 3,189,422 | 3,189,422 | - | - | - | - | - | - | - | - |
| | | | | 6,501,114 | 6,501,114 | - | - | - | - | - | - | - | - |
| 347 | Other Production ARO | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| OP | Unclassified Other Prod Plant-Acct 300 | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| **Total Other Production Plant** | | | | **1,588,336,982** | **1,588,336,982** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| Experimental Plant | | | | | | | | | | | | | |
| 103 | Experimental Plant | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| **Total Experimental Plant** | | | | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| **TOTAL PRODUCTION PLANT** | | | | **3,826,617,433** | **3,826,617,433** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| 350 | Land and Land Rights | | | | | | | | | | | | |
| | | T | SG | 5,486,720 | - | 5,486,720 | - | - | - | - | - | - | - |
| | | T | SG | 12,491,637 | - | 12,491,637 | - | - | - | - | - | - | - |
| | | T | SG | 75,262,894 | - | 75,262,894 | - | - | - | - | - | - | - |
| | | | | 93,241,252 | - | 93,241,252 | - | - | - | - | - | - | - |
| 352 | Structures and Improvements | | | | | | | | | | | | |
| | | T | S | - | - | - | - | - | - | - | - | - | - |
| | | T | SG | 1,856,223 | - | 1,856,223 | - | - | - | - | - | - | - |
| | | T | SG | 4,676,439 | - | 4,676,439 | - | - | - | - | - | - | - |
| | | T | SG | 97,272,119 | - | 97,272,119 | - | - | - | - | - | - | - |
| | | | | 103,804,780 | - | 103,804,780 | - | - | - | - | - | - | - |
| 353 | Station Equipment | | | | | | | | | | | | |
| | | STEP_UP | SG | 27,481,938 | 1,771,274 | 25,710,663 | - | - | - | - | - | - | - |
| | | STEP_UP | SG | 39,242,560 | 2,529,274 | 36,713,286 | - | - | - | - | - | - | - |
| | | STEP_UP | SG | 665,825,231 | 42,913,977 | 622,911,254 | - | - | - | - | - | - | - |
| | | | | 732,549,729 | 47,214,525 | 685,335,204 | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 354 | Towers and Fixtures | | | | | | | | | | | | |
| | | T | SG | 34,440,254 | - | 34,440,254 | - | - | - | - | - | - | - |
| | | T | SG | 35,264,886 | - | 35,264,886 | - | - | - | - | - | - | - |
| | | T | SG | 340,548,450 | - | 340,548,450 | - | - | - | - | - | - | - |
| | | | | 410,253,591 | - | 410,253,591 | - | - | - | - | - | - | - |
| 355 | Poles and Fixtures | | | | | | | | | | | | |
| | | T | S | - | - | - | - | - | - | - | - | - | - |
| | | T | SG | 15,721,805 | - | 15,721,805 | - | - | - | - | - | - | - |
| | | T | SG | 30,308,612 | - | 30,308,612 | - | - | - | - | - | - | - |
| | | T | SG | 1,150,049,256 | - | 1,150,049,256 | - | - | - | - | - | - | - |
| | | | | 1,196,079,673 | - | 1,196,079,673 | - | - | - | - | - | - | - |
| 356 | Clearing and Grading | | | | | | | | | | | | |
| | | T | SG | 42,117,472 | - | 42,117,472 | - | - | - | - | - | - | - |
| | | T | SG | 41,979,966 | - | 41,979,966 | - | - | - | - | - | - | - |
| | | T | SG | 366,510,019 | - | 366,510,019 | - | - | - | - | - | - | - |
| | | | | 450,607,457 | - | 450,607,457 | - | - | - | - | - | - | - |
| 357 | Underground Conduit | | | | | | | | | | | | |
| | | T | SG | 1,713 | - | 1,713 | - | - | - | - | - | - | - |
| | | T | SG | 24,639 | - | 24,639 | - | - | - | - | - | - | - |
| | | T | SG | 1,014,868 | - | 1,014,868 | - | - | - | - | - | - | - |
| | | | | 1,041,220 | - | 1,041,220 | - | - | - | - | - | - | - |
| 358 | Underground Conductors | | | | | | | | | | | | |
| | | T | SG | - | - | - | - | - | - | - | - | - | - |
| | | T | SG | 292,379 | - | 292,379 | - | - | - | - | - | - | - |
| | | T | SG | 2,148,868 | - | 2,148,868 | - | - | - | - | - | - | - |
| | | | | 2,441,247 | - | 2,441,247 | - | - | - | - | - | - | - |
| 359 | Roads and Trails | | | | | | | | | | | | |
| | | T | SG | 500,860 | - | 500,860 | - | - | - | - | - | - | - |
| | | T | SG | 117,206 | - | 117,206 | - | - | - | - | - | - | - |
| | | T | SG | 2,646,065 | - | 2,646,065 | - | - | - | - | - | - | - |
| | | | | 3,264,131 | - | 3,264,131 | - | - | - | - | - | - | - |
| TP | Unclassified Trans Plant - Acct 300 | | | | | | | | | | | | |
| | | T | SG | 33,452,905 | - | 33,452,905 | - | - | - | - | - | - | - |
| | | | | 33,452,905 | - | 33,452,905 | - | - | - | - | - | - | - |
| TS0 | Unclassified Trans Sub Plant - Acct 300 | | | | | | | | | | | | |
| | | T | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| **TOTAL TRANSMISSION PLANT** | | | | **3,026,735,986** | **47,214,525** | **2,979,521,461** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| 360 | Land and Land Rights | | | | | | | | | | | | |
| | | D | S | 16,501,049 | - | - | 16,501,049 | - | - | - | - | - | - |
| | | | | 16,501,049 | - | - | 16,501,049 | - | - | - | - | - | - |
| 361 | Structures and Improvements | | | | | | | | | | | | |
| | | D | S | 36,864,239 | - | - | 36,864,239 | - | - | - | - | - | - |
| | | | | 36,864,239 | - | - | 36,864,239 | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 362 | Station Equipment | | | | | | | | | | | | |
| | | D | S | 321,458,778 | - | - | 321,458,778 | - | - | - | - | - | - |
| | | | | 321,458,778 | - | - | 321,458,778 | - | - | - | - | - | - |
| 363 | Storage Battery Equipment | | | | | | | | | | | | |
| | | D | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 364 | Poles, Towers & Fixtures | | | | | | | | | | | | |
| | | D | S | 537,021,123 | - | - | 537,021,123 | - | - | - | - | - | - |
| | | | | 537,021,123 | - | - | 537,021,123 | - | - | - | - | - | - |
| 365 | Overhead Conductors | | | | | | | | | | | | |
| | | D | S | 326,142,454 | - | - | 326,142,454 | - | - | - | - | - | - |
| | | | | 326,142,454 | - | - | 326,142,454 | - | - | - | - | - | - |
| 366 | Underground Conduit | | | | | | | | | | | | |
| | | D | S | 127,274,252 | - | - | 127,274,252 | - | - | - | - | - | - |
| | | | | 127,274,252 | - | - | 127,274,252 | - | - | - | - | - | - |
| 367 | Underground Conductors | | | | | | | | | | | | |
| | | D | S | 249,806,557 | - | - | 249,806,557 | - | - | - | - | - | - |
| | | | | 249,806,557 | - | - | 249,806,557 | - | - | - | - | - | - |
| 368 | Line Transformers | | | | | | | | | | | | |
| | | D | S | 553,956,506 | - | - | 553,956,506 | - | - | - | - | - | - |
| | | | | 553,956,506 | - | - | 553,956,506 | - | - | - | - | - | - |
| 369 | Services | | | | | | | | | | | | |
| | | D | S | 373,239,647 | - | - | 373,239,647 | - | - | - | - | - | - |
| | | | | 373,239,647 | - | - | 373,239,647 | - | - | - | - | - | - |
| 370 | Meters | | | | | | | | | | | | |
| | | C_Meter | S | 109,792,499 | - | - | - | - | - | - | 109,792,499 | - | - |
| | | | | 109,792,499 | - | - | - | - | - | - | 109,792,499 | - | - |
| 371 | Installations on Customers' Premises | | | | | | | | | | | | |
| | | DL | S | 2,803,509 | - | - | - | 2,803,509 | - | - | - | - | - |
| | | | | 2,803,509 | - | - | - | 2,803,509 | - | - | - | - | - |
| 372 | Leased Property | | | | | | | | | | | | |
| | | D | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 373 | Street Lights | | | | | | | | | | | | |
| | | DL | S | 25,968,508 | - | - | - | 25,968,508 | - | - | - | - | - |
| | | | | 25,968,508 | - | - | - | 25,968,508 | - | - | - | - | - |
| DP | Unclassified Dist Plant - Acct 300 | | | | | | | | | | | | |
| | | D | S | 24,538,568 | - | - | 24,538,568 | - | - | - | - | - | - |
| | | | | 24,538,568 | - | - | 24,538,568 | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| DS0 | Unclassified Dist Sub Plant - Acct 300 | | | | | | | | | | | | |
| | | D | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| **TOTAL DISTRIBUTION PLANT** | | | | **2,705,367,690** | **-** | **-** | **2,566,803,175** | **28,772,017** | **-** | **-** | **109,792,499** | **-** | **-** |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 389 | Land and Land Rights | | | | | | | | | | | | |
| | | D_SPLIT | S | 6,116,556 | - | - | 5,803,276 | 65,051 | - | - | 248,229 | - | - |
| | | B_Center | CN | 346,514 | - | - | - | - | - | 225,735 | - | 120,779 | - |
| | | G-DGU | SG | 89 | 50 | 39 | - | - | - | - | - | - | - |
| | | G-SG | SG | 330 | 131 | 199 | - | - | - | - | - | - | - |
| | | LABOR | SO | 2,087,521 | 874,234 | 150,852 | 821,883 | 6,217 | - | 141,404 | 41,372 | 51,559 | - |
| | | | | 8,551,011 | 874,415 | 151,090 | 6,625,159 | 71,268 | - | 367,139 | 289,602 | 172,338 | - |
| 390 | Structures and Improvements | | | | | | | | | | | | |
| | | D_SPLIT | S | 44,350,073 | - | - | 42,078,535 | 471,670 | - | - | 1,799,868 | - | - |
| | | P | SE | 247,839 | 247,839 | - | - | - | - | - | - | - | - |
| | | G-DGP | SG | 90,126 | 50,319 | 39,807 | - | - | - | - | - | - | - |
| | | G-DGU | SG | 364,653 | 203,593 | 161,060 | - | - | - | - | - | - | - |
| | | B_Center | CN | 2,523,635 | - | - | - | - | - | 1,644,012 | - | 879,623 | - |
| | | G-SG | SG | 2,777,643 | 1,104,872 | 1,672,771 | - | - | - | - | - | - | - |
| | | LABOR | SO | 30,989,684 | 12,978,184 | 2,239,424 | 12,201,020 | 92,300 | - | 2,099,174 | 614,181 | 765,401 | - |
| | | | | 81,343,652 | 14,584,806 | 4,113,062 | 54,279,555 | 563,970 | - | 3,743,186 | 2,414,049 | 1,645,024 | - |
| 391 | Office Furniture & Equipment | | | | | | | | | | | | |
| | | D_SPLIT | S | 2,351,456 | - | - | 2,231,018 | 25,008 | - | - | 95,430 | - | - |
| | | G-DGP | SG | - | - | - | - | - | - | - | - | - | - |
| | | G-DGU | SG | - | - | - | - | - | - | - | - | - | - |
| | | B_Center | CN | 881,065 | - | - | - | - | - | 573,966 | - | 307,099 | - |
| | | G-SG | SG | 1,227,944 | 488,443 | 739,501 | - | - | - | - | - | - | - |
| | | P | SE | 7,002 | 7,002 | - | - | - | - | - | - | - | - |
| | | LABOR | SO | 21,998,162 | 9,212,620 | 1,589,665 | 8,660,947 | 65,520 | - | 1,490,108 | 435,979 | 543,323 | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 2,238 | 2,238 | - | - | - | - | - | - | - | - |
| | | | | 26,467,867 | 9,710,304 | 2,329,165 | 10,891,965 | 90,528 | - | 2,064,074 | 531,409 | 850,422 | - |
| 392 | Transportation Equipment | | | | | | | | | | | | |
| | | D_SPLIT | S | 30,344,593 | - | - | 28,790,392 | 322,720 | - | - | 1,231,481 | - | - |
| | | LABOR | SO | 1,904,071 | 797,407 | 137,595 | 749,656 | 5,671 | - | 128,978 | 37,737 | 47,028 | - |
| | | G-SG | SG | 6,641,901 | 2,641,970 | 3,999,931 | - | - | - | - | - | - | - |
| | | B_Center | CN | - | - | - | - | - | - | - | - | - | - |
| | | G-DGU | SG | 179,498 | 100,217 | 79,281 | - | - | - | - | - | - | - |
| | | P | SE | 86,224 | 86,224 | - | - | - | - | - | - | - | - |
| | | G-DGP | SG | 18,984 | 10,599 | 8,385 | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 12,005 | 12,005 | - | - | - | - | - | - | - | - |
| | | | | 39,187,276 | 3,648,422 | 4,225,191 | 29,540,048 | 328,391 | - | 128,978 | 1,269,217 | 47,028 | - |
| 393 | Stores Equipment | | | | | | | | | | | | |
| | | D_SPLIT | S | 2,998,461 | - | - | 2,844,885 | 31,889 | - | - | 121,687 | - | - |
| | | G-DGP | SG | - | - | - | - | - | - | - | - | - | - |
| | | G-DGU | SG | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SO | 66,627 | 27,903 | 4,815 | 26,232 | 198 | - | 4,513 | 1,320 | 1,646 | - |
| | | G-SG | SG | 1,858,102 | 739,103 | 1,118,999 | - | - | - | - | - | - | - |
| | | P | SG | 14,510 | 14,510 | - | - | - | - | - | - | - | - |
| | | | | 4,937,700 | 781,516 | 1,123,813 | 2,871,117 | 32,088 | - | 4,513 | 123,008 | 1,646 | - |
| 394 | Tools, Shop & Garage Equipment | | | | | | | | | | | | |
| | | D_SPLIT | S | 10,911,877 | - | - | 10,352,988 | 116,050 | - | - | 442,839 | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | G-DGP | SG | 6,446 | 3,599 | 2,847 | - | - | - | - | - | - | - |
| | | G-SG | SG | 6,168,407 | 2,453,627 | 3,714,780 | - | - | - | - | - | - | - |
| | | LABOR | SO | 494,302 | 207,009 | 35,720 | 194,613 | 1,472 | - | 33,483 | 9,797 | 12,209 | - |
| | | P | SE | 33,106 | 33,106 | - | - | - | - | - | - | - | - |
| | | G-SG | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 24,172 | 24,172 | - | - | - | - | - | - | - | - |
| | | | | 17,638,311 | 2,721,514 | 3,753,347 | 10,547,601 | 117,522 | - | 33,483 | 452,635 | 12,209 | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 395 | Laboratory Equipment | | | | | | | | | | | | |
| | | D_SPLIT | S | 10,321,264 | - | - | 9,792,626 | 109,768 | - | - | 418,870 | - | - |
| | | G-DGP | SG | - | - | - | - | - | - | - | - | - | - |
| | | G-DGU | SG | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SO | 1,390,682 | 582,404 | 100,496 | 547,529 | 4,142 | - | 94,202 | 27,562 | 34,348 | - |
| | | P | SE | 349,480 | 349,480 | - | - | - | - | - | - | - | - |
| | | G-SG | SG | 1,995,544 | 793,774 | 1,201,770 | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 3,770 | 3,770 | - | - | - | - | - | - | - | - |
| | | | | 14,060,740 | 1,729,428 | 1,302,265 | 10,340,155 | 113,910 | - | 94,202 | 446,432 | 34,348 | - |
| 396 | Power Operated Equipment | | | | | | | | | | | | |
| | | D_SPLIT | S | 52,665,956 | - | - | 49,968,491 | 560,111 | - | - | 2,137,353 | - | - |
| | | G-DGP | SG | 70,436 | 39,326 | 31,110 | - | - | - | - | - | - | - |
| | | G-SG | SG | 12,703,138 | 5,052,968 | 7,650,170 | - | - | - | - | - | - | - |
| | | LABOR | SO | 1,279,032 | 535,647 | 92,427 | 503,571 | 3,809 | - | 86,639 | 25,349 | 31,590 | - |
| | | G-DGU | SG | 198,848 | 111,021 | 87,828 | - | - | - | - | - | - | - |
| | | P | SE | 62,341 | 62,341 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 66,979,751 | 5,801,302 | 7,861,535 | 50,472,062 | 563,920 | - | 86,639 | 2,162,702 | 31,590 | - |
| 397 | Communication Equipment | | | | | | | | | | | | |
| | | D_SPLIT | S | 124,669,936 | - | - | 118,284,546 | 1,325,885 | - | - | 5,059,506 | - | - |
| | | G-DGP | SG | - | - | - | - | - | - | - | - | - | - |
| | | G-DGU | SG | 37,439 | 20,903 | 16,536 | - | - | - | - | - | - | - |
| | | LABOR | SO | 44,276,794 | 18,542,699 | 3,199,597 | 17,432,319 | 131,874 | - | 2,999,215 | 877,517 | 1,093,573 | - |
| | | B_Center | CN | 470,976 | - | - | - | - | - | 306,815 | - | 164,161 | - |
| | | G-SG | SG | 52,646,359 | 20,941,312 | 31,705,048 | - | - | - | - | - | - | - |
| | | P | SE | 42,417 | 42,417 | - | - | - | - | - | - | - | - |
| | | G-SG | SG | - | - | - | - | - | - | - | - | - | - |
| | | G-SG | SG | 4,472 | 1,779 | 2,693 | - | - | - | - | - | - | - |
| | | | | 222,148,393 | 39,549,109 | 34,923,874 | 135,716,865 | 1,457,759 | - | 3,306,030 | 5,937,023 | 1,257,734 | - |
| 398 | Misc. Equipment | | | | | | | | | | | | |
| | | D_SPLIT | S | 1,374,243 | - | - | 1,303,857 | 14,615 | - | - | 55,771 | - | - |
| | | G-DGP | SG | - | - | - | - | - | - | - | - | - | - |
| | | G-DGU | SG | - | - | - | - | - | - | - | - | - | - |
| | | B_Center | CN | 21,758 | - | - | - | - | - | 14,174 | - | 7,584 | - |
| | | LABOR | SO | 431,943 | 180,894 | 31,214 | 170,061 | 1,287 | - | 29,259 | 8,561 | 10,668 | - |
| | | P | SE | 1,045 | 1,045 | - | - | - | - | - | - | - | - |
| | | G-SG | SG | 837,112 | 332,981 | 504,131 | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 2,666,100 | 514,919 | 535,345 | 1,473,918 | 15,902 | - | 43,433 | 64,332 | 18,252 | - |
| 399 | Coal Mine | | | | | | | | | | | | |
| | | P | SE | 11,665,695 | 11,665,695 | - | - | - | - | - | - | - | - |
| MP | Unckassified Mine Plar | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | | | 11,665,695 | 11,665,695 | - | - | - | - | - | - | - | - |
| 399L | WIDCO Capital Lease | | | | | | | | | | | | |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | Remove Capital Leases | | | - | - | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | - | - | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1011390 | General Capital Leases | | | | | | | | | | | | |
| | | D_SPLIT | S | 691,142 | - | - | 655,742 | 7,350 | - | - | 28,049 | - | - |
| | | P | SG | 2,166,359 | 2,166,359 | - | - | - | - | - | - | - | - |
| | | LABOR | SO | - | - | - | - | - | - | - | - | - | - |
| | | | | 2,857,500 | 2,166,359 | - | 655,742 | 7,350 | - | - | 28,049 | - | - |
| | Remove Capital Leases | | | (2,857,500) | (2,166,359) | - | (655,742) | (7,350) | - | - | (28,049) | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 1011346 | General Gas Line Capital Leases | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| | Remove Capital Leases | | | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| GP | Unclassified Gen Plant - Acct 300 | | | | | | | | | | | | |
| | | D_SPLIT | S | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SO | 17,939,437 | 7,512,865 | 1,296,367 | 7,062,977 | 53,431 | - | 1,215,179 | 355,540 | 443,078 | - |
| | | B_Center | CN | - | - | - | - | - | - | - | - | - | - |
| | | G-SG | SG | - | - | - | - | - | - | - | - | - | - |
| | | G-DGP | SG | - | - | - | - | - | - | - | - | - | - |
| | | G-DGU | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 17,939,437 | 7,512,865 | 1,296,367 | 7,062,977 | 53,431 | - | 1,215,179 | 355,540 | 443,078 | - |
| 399G | Unclassified Gen Plant - Acct 300 | | | | | | | | | | | | |
| | | D_SPLIT | S | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SO | - | - | - | - | - | - | - | - | - | - |
| | | G-SG | SG | - | - | - | - | - | - | - | - | - | - |
| | | G-DGP | SG | - | - | - | - | - | - | - | - | - | - |
| | | G-DGU | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| **TOTAL GENERAL PLANT** | | | | **513,585,933** | **99,094,295** | **61,615,055** | **319,821,422** | **3,408,688** | **-** | **11,086,856** | **14,045,949** | **4,513,667** | **-** |
| 301 | Organization | | | | | | | | | | | | |
| | | D_SPLIT | S | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SO | - | - | - | - | - | - | - | - | - | - |
| | | I-SG | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 302 | Franchise & Consent | | | | | | | | | | | | |
| | | D_SPLIT | S | - | - | - | - | - | - | - | - | - | - |
| | | I-SG | SG | 4,368,333 | 2,777,371 | 1,590,962 | - | - | - | - | - | - | - |
| | | I-DGP | SG | 27,790,447 | 27,790,447 | - | - | - | - | - | - | - | - |
| | | I-DGU | SG | 2,622,724 | 2,622,724 | - | - | - | - | - | - | - | - |
| | | I-DGP | SG | - | - | - | - | - | - | - | - | - | - |
| | | I-DGU | SG | 128,398 | 128,398 | - | - | - | - | - | - | - | - |
| | | | | 34,909,902 | 33,318,940 | 1,590,962 | - | - | - | - | - | - | - |
| 303 | Miscellaneous Intangible Plant | | | | | | | | | | | | |
| | | D_SPLIT | S | 4,606,407 | - | - | 4,370,474 | 48,990 | - | - | 186,943 | - | - |
| | | LABOR | SG | 52,366,046 | 21,930,400 | 3,784,155 | 20,617,157 | 155,967 | - | 3,547,163 | 1,037,837 | 1,293,366 | - |
| | | LABOR | SO | 148,714,363 | 62,280,156 | 10,746,624 | 58,550,676 | 442,932 | - | 10,073,591 | 2,947,353 | 3,673,030 | - |
| | | P | SE | 1,241 | 1,241 | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | CSS_SYS | CN | 70,461,152 | - | - | - | - | - | 31,237,777 | 16,440,935 | 22,782,439 | - |
| | | I-DGP | SG | - | - | - | - | - | - | - | - | - | - |
| | | I-DGP | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 276,149,209 | 84,211,797 | 14,530,779 | 83,538,307 | 647,889 | - | 44,858,531 | 20,613,069 | 27,748,835 | - |
| 303 | Less Non-Utility Plant | | | | | | | | | | | | |
| | | I-SITUS | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| IP | Unclassified Intangible Plant - Acct 300 | | | | | | | | | | | | |
| | | D_SPLIT | S | - | - | - | - | - | - | - | - | - | - |
| | | I-SG | SG | - | - | - | - | - | - | - | - | - | - |
| | | I-DGU | SG | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SO | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| **TOTAL INTANGIBLE PLANT** | | | | **311,059,111** | **117,530,738** | **16,121,741** | **83,538,307** | **647,889** | **-** | **44,858,531** | **20,613,069** | **27,748,835** | **-** |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **TOTAL ELECTRIC PLANT IN SERVICE** | | | | **10,383,366,153** | **4,090,456,990** | **3,057,258,257** | **2,970,162,905** | **32,828,594** | **-** | **55,945,387** | **144,451,516** | **32,262,503** | **-** |
| 105 | Plant Held For Future Use | | | | | | | | | | | | |
| | | D_SPLIT | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | T | SG | 408,094 | - | 408,094 | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | G | SG | (408,094) | (79,561) | (143,540) | (175,384) | - | - | (4,456) | (5,152) | - | - |
| | | | | - | (79,561) | 264,553 | (175,384) | - | - | (4,456) | (5,152) | - | - |
| 114 | Electric Plant Acquisition Adjustments | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | 38,902,639 | 38,902,639 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 38,902,639 | 38,902,639 | - | - | - | - | - | - | - | - |
| 115 | Accum Provision for Asset Acquisition Adjustments | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | (38,199,390) | (38,199,390) | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | (38,199,390) | (38,199,390) | - | - | - | - | - | - | - | - |
| 128 | Pensions | | | | | | | | | | | | |
| | | LABOR | SO | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 124 | Weatherization | | | | | | | | | | | | |
| | | DSM | S | - | - | - | - | - | - | - | - | - | - |
| | | DSM | SO | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 182W | Weatherization | | | | | | | | | | | | |
| | | DSM | S | - | - | - | - | - | - | - | - | - | - |
| | | DSM | SG | - | - | - | - | - | - | - | - | - | - |
| | | DSM | SG | - | - | - | - | - | - | - | - | - | - |
| | | DSM | SO | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 186W | Weatherization | | | | | | | | | | | | |
| | | DSM | S | - | - | - | - | - | - | - | - | - | - |
| | | DSM | CN | - | - | - | - | - | - | - | - | - | - |
| | | DSM | CNP | - | - | - | - | - | - | - | - | - | - |
| | | DSM | SG | - | - | - | - | - | - | - | - | - | - |
| | | DSM | SO | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| | Total Weatherization | | | - | - | - | - | - | - | - | - | - | - |
| 151 | Fuel Stock | | | | | | | | | | | | |
| | | P | DEU | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | 45,157,610 | 45,157,610 | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | | | 45,157,610 | 45,157,610 | - | - | - | - | - | - | - | - |
| 152 | Fuel Stock - Undistributed | | | | | | | | | | | | |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 25316 | DG&T Working Capital Deposit | | | | | | | | | | | | |
| | | P | SE | (233,547) | (233,547) | - | - | - | - | - | - | - | - |
| | | | | (233,547) | (233,547) | - | - | - | - | - | - | - | - |
| 25317 | DG&T Working Capital Deposit | | | | | | | | | | | | |
| | | P | SE | (1,379,884) | (1,379,884) | - | - | - | - | - | - | - | - |
| | | | | (1,379,884) | (1,379,884) | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 25319 | Provo Working Capital Deposit | | | | | | | | | | | | |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| | Total Fuel Stock | | | 43,544,178 | 43,544,178 | - | - | - | - | - | - | - | - |
| 154 | Materials and Supplies | | | | | | | | | | | | |
| | | MSS | S | 92,111,560 | 67,557,192 | 1,374,249 | 22,536,931 | - | - | - | 643,188 | - | - |
| | | MSS | SG | (34,091) | (25,003) | (509) | (8,341) | - | - | - | (238) | - | - |
| | | MSS | SE | - | - | - | - | - | - | - | - | - | - |
| | | MSS | SO | (226,098) | (165,827) | (3,373) | (55,319) | - | - | - | (1,579) | - | - |
| | | MSS | SG | 36,041,827 | 26,434,083 | 537,722 | 8,818,352 | - | - | - | 251,670 | - | - |
| | | MSS | SG | 9,124 | 6,692 | 136 | 2,232 | - | - | - | 64 | - | - |
| | | MSS | SNPD | (329,812) | (241,893) | (4,921) | (80,695) | - | - | - | (2,303) | - | - |
| | | MSS | SG | - | - | - | - | - | - | - | - | - | - |
| | | MSS | SG | - | - | - | - | - | - | - | - | - | - |
| | | MSS | SG | - | - | - | - | - | - | - | - | - | - |
| | | MSS | SG | - | - | - | - | - | - | - | - | - | - |
| | | MSS | SG | 2,322,954 | 1,703,720 | 34,657 | 568,357 | - | - | - | 16,221 | - | - |
| | | MSS | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 129,895,465 | 95,268,964 | 1,937,962 | 31,781,517 | - | - | - | 907,022 | - | - |
| 158 | WA GHG Allocation Inventory | | | | | | | | | | | | |
| | | MSS | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 25318 | Provo Working Capital Deposit | | | | | | | | | | | | |
| | | MSS | SG | (73,394) | (53,829) | (1,095) | (17,957) | - | - | - | (512) | - | - |
| | | | | (73,394) | (53,829) | (1,095) | (17,957) | - | - | - | (512) | - | - |
| | Total Materials & Supplies | | | 129,822,071 | 95,215,135 | 1,936,867 | 31,763,560 | - | - | - | 906,510 | - | - |
| 165 | Prepayments | | | | | | | | | | | | |
| | | LABOR | S | 4,549,813 | 1,905,418 | 328,785 | 1,791,317 | 13,551 | - | 308,195 | 90,172 | 112,374 | - |
| | | GP | GPS | 54,209 | 21,355 | 15,961 | 15,507 | 171 | - | 292 | 754 | 168 | - |
| | | PT | SG | 1,649,178 | 920,830 | 728,348 | - | - | - | - | - | - | - |
| | | P | SE | 154,795 | 154,795 | - | - | - | - | - | - | - | - |
| | | LABOR | SO | 10,430,189 | 4,368,064 | 753,722 | 4,106,494 | 31,065 | - | 706,519 | 206,715 | 257,611 | - |
| | | | | 16,838,184 | 7,370,462 | 1,826,817 | 5,913,318 | 44,788 | - | 1,015,005 | 297,641 | 370,153 | - |
| 182M | Misc Regulatory Assets | | | | | | | | | | | | |
| | | DDS2 | S | 75,123 | 87,365 | (1,726) | (10,027) | (13) | - | (287) | (84) | (105) | - |
| | | DEFSG | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SGCT | - | - | - | - | - | - | - | - | - | - |
| | | DEFSG | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | 33,785,672 | 33,785,672 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SO | 23,420,768 | 9,808,394 | 1,692,467 | 9,221,045 | 69,757 | - | 1,586,472 | 464,174 | 578,459 | - |
| | | | | 57,281,563 | 43,681,431 | 1,690,741 | 9,211,018 | 69,744 | - | 1,586,185 | 464,089 | 578,354 | - |
| 186M | Misc Deferred Debits | | | | | | | | | | | | |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | LABOR | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | DEFSG | SG | 39,033,308 | 36,388,768 | 2,644,540 | - | - | - | - | - | - | - |
| | | LABOR | SO | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | 80,732 | 80,732 | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | GP | EXCTAX | - | - | - | - | - | - | - | - | - | - |
| | | | | 39,114,040 | 36,469,500 | 2,644,540 | - | - | - | - | - | - | - |
| Working Capital | | | | | | | | | | | | | |
| CWC | Cash Working Capital | | | | | | | | | | | | |
| | | CWC | S | 36,361,381 | 24,457,038 | 3,283,362 | 7,365,647 | 50,679 | - | 747,156 | 258,820 | 198,679 | 0 |
| | | CWC | SO | - | - | - | - | - | - | - | - | - | - |
| | | CWC | SE | - | - | - | - | - | - | - | - | - | - |
| | | | | 36,361,381 | 24,457,038 | 3,283,362 | 7,365,647 | 50,679 | - | 747,156 | 258,820 | 198,679 | 0 |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| OWC | Other Work. Cap. | | | | | | | | | | | | |
| 131 | Cash | GP | SNP | - | - | - | - | - | - | - | - | - | - |
| 135 | Working Funds | GP | SG | - | - | - | - | - | - | - | - | - | - |
| 141 | Notes Receivable | GP | SO | - | - | - | - | - | - | - | - | - | - |
| 143 | Other A/R | LABOR | SO | 18,532,802 | 7,761,361 | 1,339,246 | 7,296,592 | 55,198 | - | 1,255,372 | 367,300 | 457,734 | - |
| 232 | A/P | LABOR | S | - | - | - | - | - | - | - | - | - | - |
| 232 | A/P | LABOR | SO | (1,772,159) | (742,163) | (128,062) | (697,721) | (5,278) | - | (120,042) | (35,122) | (43,770) | - |
| 232 | A/P | P | SE | (741,683) | (741,683) | - | - | - | - | - | - | - | - |
| 232 | A/P | P | SG | (1,242,552) | (1,242,552) | - | - | - | - | - | - | - | - |
| 2533 | Other Msc. Df. Crd. | P | S | - | - | - | - | - | - | - | - | - | - |
| 2533 | Other Msc. Df. Crd. | P | SE | (2,932,940) | (2,932,940) | - | - | - | - | - | - | - | - |
| 230 | Asset Retir. Oblig. | P | SE | - | - | - | - | - | - | - | - | - | - |
| 230 | Asset Retir. Oblig. | P | S | - | - | - | - | - | - | - | - | - | - |
| 254 | Decom. Reg Liability | P | SG | - | - | - | - | - | - | - | - | - | - |
| 254 | Reclam. Reg Liability | P | SE | - | - | - | - | - | - | - | - | - | - |
| 2533 | Cholla Reclamation | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | | | 11,843,468 | 2,102,022 | 1,211,183 | 6,598,872 | 49,920 | - | 1,135,330 | 332,177 | 413,964 | - |
| Total Working Capital | | | | 48,204,849 | 26,559,060 | 4,494,545 | 13,964,519 | 100,599 | - | 1,882,486 | 590,997 | 612,643 | 0 |
| Miscellaneous Rate Base | | | | | | | | | | | | | |
| 18221 | Unrec Plant & Reg Study Costs | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 18222 | Nuclear Plant - Trojan | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | TROJP | - | - | - | - | - | - | - | - | - | - |
| | | P | TROJD | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 1869 | Misc Deferred Debits-Trojan | | | | | | | | | | | | |
| | | P | S | (98,566) | (98,566) | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | (98,566) | (98,566) | - | - | - | - | - | - | - | - |
| TOTAL MISCELLANEOUS RATE BASE | | | | (98,566) | (98,566) | - | - | - | - | - | - | - | - |
| **TOTAL RATE BASE ADDITIONS** | | | | **335,409,568** | **253,364,888** | **12,858,063** | **60,677,030** | **215,131** | **-** | **4,479,221** | **2,254,085** | **1,561,150** | **0** |
| 235 | Customer Service Deposits | | | | | | | | | | | | |
| | | C_BILLING | S | - | - | - | - | - | - | - | - | - | - |
| | | C_BILLING | CN | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 2281 | Prov for Property Insur | LABOR | S | 31,639,210 | 13,250,199 | 2,286,361 | 12,456,746 | 94,234 | - | 2,143,172 | 627,054 | 781,443 | - |
| 2282 | Prov for Injuries & Dar | LABOR | SO | - | - | - | - | - | - | - | - | - | - |
| 2282 | Prov for Injuries & Dar | LABOR | S | 5,479,612 | 2,294,809 | 395,976 | 2,157,391 | 16,321 | - | 371,177 | 108,600 | 135,339 | - |
| 2283 | Prov for Pensions and E | LABOR | SO | (343,535) | (143,869) | (24,825) | (135,254) | (1,023) | - | (23,270) | (6,808) | (8,485) | - |
| 2283 | Prov for Pensions and E | LABOR | S | - | - | - | - | - | - | - | - | - | - |
| 25335 | Pens Oblig | LABOR | SE | (30,321,356) | (12,698,295) | (2,191,128) | (11,937,891) | (90,309) | - | (2,053,903) | (600,936) | (748,894) | - |
| 254 | Reg Liabilities - Insurar | LABOR | SO | (9,278,417) | (3,885,713) | (670,491) | (3,653,027) | (27,635) | - | (628,500) | (183,888) | (229,164) | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | (2,824,487) | (1,182,868) | (204,107) | (1,112,035) | (8,412) | - | (191,325) | (55,978) | (69,761) | - |
| 22841 | Accum Misc Oper Provisions - Other | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | (63,148) | (63,148) | - | - | - | - | - | - | - | - |
| | | | | (63,148) | (63,148) | - | - | - | - | - | - | - | - |
| 254105 | ARO | P | S | - | - | - | - | - | - | - | - | - | - |
| 230 | ARO | P | TROJD | (1,860,674) | (1,860,674) | - | - | - | - | - | - | - | - |
| 254105 | ARO | P | TROJD | - | - | - | - | - | - | - | - | - | - |
| 254 | | P | S | (338,613,472) | (338,613,472) | - | - | - | - | - | - | - | - |
| | | | | (340,474,146) | (340,474,146) | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 252 | Customer Advances for Construction | | | | | | | | | | | | |
| | | D_SPLIT | S | (5,177,396) | - | - | (4,912,218) | (55,062) | - | - | (210,115) | - | - |
| | | T | SE | - | - | - | - | - | - | - | - | - | - |
| | | T | SG | (41,481,126) | - | (41,481,126) | - | - | - | - | - | - | - |
| | | D_SPLIT | SO | - | - | - | - | - | - | - | - | - | - |
| | | B_Center | CN | - | - | - | - | - | - | - | - | - | - |
| | | | | (46,658,522) | - | (41,481,126) | (4,912,218) | (55,062) | - | - | (210,115) | - | - |
| 25398 | SO2 Emissions | | | | | | | | | | | | |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 25399 | Other Deferred Credits | | | | | | | | | | | | |
| | | D_SPLIT | S | (331,064) | - | - | (314,108) | (3,521) | - | - | (13,436) | - | - |
| | | LABOR | SO | (3,339,904) | (1,398,720) | (241,353) | (1,314,961) | (9,948) | - | (226,238) | (66,193) | (82,491) | - |
| | | P | SG | (81,921,571) | (81,921,571) | - | - | - | - | - | - | - | - |
| | | P | SE | (4,157,179) | (4,157,179) | - | - | - | - | - | - | - | - |
| | | | | (89,749,718) | (87,477,470) | (241,353) | (1,629,069) | (13,469) | - | (226,238) | (79,629) | (82,491) | - |
| 190 | Accumulated Deferred Income Taxes | | | | | | | | | | | | |
| | | D_SPLIT | S | 80,908,155 | - | - | 76,764,172 | 860,471 | - | - | 3,283,512 | - | - |
| | | CSS_SYS | CN | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SO | 12,786,344 | 5,354,799 | 923,986 | 5,034,141 | 38,083 | - | 866,119 | 253,411 | 315,804 | - |
| | | P | GPS | - | - | - | - | - | - | - | - | - | - |
| | | IBT | IBT | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | C_BILLING | BADDEBT | 2,482,069 | - | - | - | - | - | 2,482,069 | - | - | - |
| | | P | TROJD | 308,510 | 308,510 | - | - | - | - | - | - | - | - |
| | | P | SG | 432,428 | 432,428 | - | - | - | - | - | - | - | - |
| | | P | SE | 1,118,875 | 1,118,875 | - | - | - | - | - | - | - | - |
| | | LABOR | SNP | - | - | - | - | - | - | - | - | - | - |
| | | D_SPLIT | SNPD | 577,021 | - | - | 547,467 | 6,137 | - | - | 23,417 | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | 98,613,403 | 7,214,612 | 923,986 | 82,345,780 | 904,691 | - | 3,348,189 | 3,560,341 | 315,804 | - |
| 281 | Accumulated Deferred Income Taxes | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | PT | SG | (0) | (0) | (0) | - | - | - | - | - | - | - |
| | | T | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | (0) | (0) | (0) | - | - | - | - | - | - | - |
| 282 | Accumulated Deferred Income Taxes | | | | | | | | | | | | |
| | | GP | S | (67,698,629) | (26,669,418) | (19,933,053) | (19,365,199) | (214,040) | - | (364,759) | (941,811) | (210,349) | - |
| | | CSS_SYS | CN | (6,702) | - | - | - | - | - | (2,971) | (1,564) | (2,167) | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | ACCMDIT | DITBAL | (95,790) | (43,917) | (28,179) | (23,568) | - | - | (58) | (67) | - | - |
| | | PT | SNPD | - | - | - | - | - | - | - | - | - | - |
| | | PT | CIAC | - | - | - | - | - | - | - | - | - | - |
| | | C_Service | SNP | (65,144) | - | - | - | - | - | - | - | (65,144) | - |
| | | P | SG-U | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SO | (38,781,572) | (16,241,352) | (2,802,493) | (15,268,782) | (115,507) | - | (2,626,980) | (768,608) | (957,849) | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | P | SE | (327,393) | (327,393) | - | - | - | - | - | - | - | - |
| | | P | SG | (667,471,869) | (667,471,869) | - | - | - | - | - | - | - | - |
| | | | | (774,447,098) | (710,753,949) | (22,763,726) | (34,657,550) | (329,547) | - | (2,994,769) | (1,712,050) | (1,235,509) | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 283 | Accumulated Deferred Income Taxes | | | | | | | | | | | | |
| | | GP | S | (8,897,652) | (3,505,170) | (2,619,807) | (2,545,174) | (28,131) | - | (47,940) | (123,783) | (27,646) | - |
| | | P | SG | (413,127) | (413,127) | - | - | - | - | - | - | - | - |
| | | P | SE | (161,499) | (161,499) | - | - | - | - | - | - | - | - |
| | | LABOR | SO | (8,448,561) | (3,538,177) | (610,523) | (3,326,303) | (25,163) | - | (572,287) | (167,441) | (208,667) | - |
| | | GP | GPS | (2,517,329) | (991,685) | (741,198) | (720,082) | (7,959) | - | (13,563) | (35,021) | (7,822) | - |
| | | LABOR | SNP | (138,531) | (58,015) | (10,011) | (54,541) | (413) | - | (9,384) | (2,746) | (3,422) | - |
| | | P | TROJD | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SGCT | - | - | - | - | - | - | - | - | - | - |
| | | IBT | IBT | - | - | - | - | - | - | - | - | - | - |
| | | | | (20,576,699) | (8,667,673) | (3,981,539) | (6,646,100) | (61,666) | - | (643,175) | (328,990) | (247,557) | - |
| TOTAL ACCUMULATED DEF INCOME TAX | | | | (696,410,395) | (712,207,010) | (25,821,278) | 41,042,129 | 513,478 | - | (289,755) | 1,519,301 | (1,167,261) | - |
| 255 | Accumulated Investment Tax Credit | | | | | | | | | | | | |
| | | LABOR | S | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | ITC84 | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | ITC85 | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | ITC86 | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | ITC88 | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | ITC89 | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | ITC90 | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SG | (40,918) | (17,136) | (2,957) | (16,110) | (122) | - | (2,772) | (811) | (1,011) | - |
| | | | | (40,918) | (17,136) | (2,957) | (16,110) | (122) | - | (2,772) | (811) | (1,011) | - |
| **TOTAL RATE BASE DEDUCTIONS** | | | | **(1,176,221,333)** | **(1,141,421,778)** | **(67,750,822)** | **33,372,697** | **436,413** | **-** | **(710,089)** | **1,172,768** | **(1,320,523)** | **-** |
| 108SP | Steam Prod Plant Accumulated Depr | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | (221,760,155) | (221,760,155) | - | - | - | - | - | - | - | - |
| | | P | SG | (206,798,180) | (206,798,180) | - | - | - | - | - | - | - | - |
| | | P | SG | (1,074,640,597) | (1,074,640,597) | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | (1,503,198,932) | (1,503,198,932) | - | - | - | - | - | - | - | - |
| 108NP | Nuclear Prod Plant Accumulated Depr | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 108HP | Hydraulic Prod Plant Accum Depr | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | (39,230,371) | (39,230,371) | - | - | - | - | - | - | - | - |
| | | P | SG | (8,751,803) | (8,751,803) | - | - | - | - | - | - | - | - |
| | | P | SG | (59,903,905) | (59,903,905) | - | - | - | - | - | - | - | - |
| | | P | SG | (23,614,451) | (23,614,451) | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | P | SG | (1,779,628) | (1,779,628) | - | - | - | - | - | - | - | - |
| | | | | (133,280,158) | (133,280,158) | - | - | - | - | - | - | - | - |
| 108OP | Other Production Plant - Accum Depr | | | | | | | | | | | | |
| | | P | S | (173,154,068) | (173,154,068) | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | (24,587,538) | (24,587,538) | - | - | - | - | - | - | - | - |
| | | P | SG | (172,503,291) | (172,503,291) | - | - | - | - | - | - | - | - |
| | | P | SG | (13,478,790) | (13,478,790) | - | - | - | - | - | - | - | - |
| | | | | (383,723,687) | (383,723,687) | - | - | - | - | - | - | - | - |
| 108EP | Experimental Plant - Accum Depr | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| **TOTAL PRODUCTION PLANT DEPRECIATION** | | | | **(2,020,202,776)** | **(2,020,202,776)** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| 108TP | Transmission Plant Accumulated Depr | | | | | | | | | | | | |
| | | T_Split | S | - | - | - | - | - | - | - | - | - | - |
| | | T_Split | SG | (93,970,067) | (1,465,854) | (92,504,214) | - | - | - | - | - | - | - |
| | | T_Split | SG | (113,175,930) | (1,765,449) | (111,410,482) | - | - | - | - | - | - | - |
| | | T_Split | SG | (444,839,407) | (6,939,119) | (437,900,287) | - | - | - | - | - | - | - |
| **TOTAL TRANS PLANT ACCUM DEPR** | | | | **(651,985,404)** | **(10,170,422)** | **(641,814,983)** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| 108360 | Land and Land Rights | | | | | | | | | | | | |
| | | D | S | (2,858,488) | - | - | (2,858,488) | - | - | - | - | - | - |
| | | | | (2,858,488) | - | - | (2,858,488) | - | - | - | - | - | - |
| 108361 | Structures and Improvements | | | | | | | | | | | | |
| | | D | S | (10,548,995) | - | - | (10,548,995) | - | - | - | - | - | - |
| | | | | (10,548,995) | - | - | (10,548,995) | - | - | - | - | - | - |
| 108362 | Station Equipment | | | | | | | | | | | | |
| | | D | S | (112,577,498) | - | - | (112,577,498) | - | - | - | - | - | - |
| | | | | (112,577,498) | - | - | (112,577,498) | - | - | - | - | - | - |
| 108363 | Storage Battery Equipment | | | | | | | | | | | | |
| | | D | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 108364 | Poles, Towers & Fixtures | | | | | | | | | | | | |
| | | D | S | (276,584,933) | - | - | (276,584,933) | - | - | - | - | - | - |
| | | | | (276,584,933) | - | - | (276,584,933) | - | - | - | - | - | - |
| 108365 | Overhead Conductors | | | | | | | | | | | | |
| | | D | S | (147,706,066) | - | - | (147,706,066) | - | - | - | - | - | - |
| | | | | (147,706,066) | - | - | (147,706,066) | - | - | - | - | - | - |
| 108366 | Underground Conduit | | | | | | | | | | | | |
| | | D | S | (53,984,823) | - | - | (53,984,823) | - | - | - | - | - | - |
| | | | | (53,984,823) | - | - | (53,984,823) | - | - | - | - | - | - |
| 108367 | Underground Conductors | | | | | | | | | | | | |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | D | S | (107,614,232) | - | - | (107,614,232) | - | - | - | - | - | - |
| | | | | (107,614,232) | - | - | (107,614,232) | - | - | - | - | - | - |
| 108368 | Line Transformers | | | | | | | | | | | | |
| | | D | S | (270,462,078) | - | - | (270,462,078) | - | - | - | - | - | - |
| | | | | (270,462,078) | - | - | (270,462,078) | - | - | - | - | - | - |
| 108369 | Services | | | | | | | | | | | | |
| | | D | S | (161,639,339) | - | - | (161,639,339) | - | - | - | - | - | - |
| | | | | (161,639,339) | - | - | (161,639,339) | - | - | - | - | - | - |
| 108370 | Meters | | | | | | | | | | | | |
| | | C_Meter | S | (34,040,310) | - | - | - | - | - | - | (34,040,310) | - | - |
| | | | | (34,040,310) | - | - | - | - | - | - | (34,040,310) | - | - |
| 108371 | Installations on Customers' Premises | | | | | | | | | | | | |
| | | DL | S | (2,164,552) | - | - | - | (2,164,552) | - | - | - | - | - |
| | | | | (2,164,552) | - | - | - | (2,164,552) | - | - | - | - | - |
| 108372 | Leased Property | | | | | | | | | | | | |
| | | D | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 108373 | Street Lights | | | | | | | | | | | | |
| | | DL | S | (12,616,113) | - | - | - | (12,616,113) | - | - | - | - | - |
| | | | | (12,616,113) | - | - | - | (12,616,113) | - | - | - | - | - |
| 108D00 | Unclassified Dist Plant - Acct 300 | | | | | | | | | | | | |
| | | D_SPLIT | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 108DS | Unclassified Dist Sub Plant - Acct 300 | | | | | | | | | | | | |
| | | D_SPLIT | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 108DP | Unclassified Dist Sub Plant - Acct 300 | | | | | | | | | | | | |
| | | D_SPLIT | S | 685,999 | - | - | 650,863 | 7,296 | - | - | 27,840 | - | - |
| | | | | 685,999 | - | - | 650,863 | 7,296 | - | - | 27,840 | - | - |
| **TOTAL DISTRIBUTION PLANT DEPR** | | | | **(1,192,111,426)** | **-** | **-** | **(1,143,325,587)** | **(14,773,369)** | **-** | **-** | **(34,012,470)** | **-** | **-** |
| 108GP | General Plant Accumulated Depr | | | | | | | | | | | | |
| | | D_SPLIT | S | (96,741,359) | - | - | (91,786,425) | (1,028,860) | - | - | (3,926,075) | - | - |
| | | G-DGP | SG | (127,180) | (71,007) | (56,173) | - | - | - | - | - | - | - |
| | | G-DGU | SG | (562,467) | (314,036) | (248,431) | - | - | - | - | - | - | - |
| | | G-SG | SG | (41,918,891) | (16,674,212) | (25,244,679) | - | - | - | - | - | - | - |
| | | B_Center | CN | (1,684,429) | - | - | - | - | - | (1,097,314) | - | (587,115) | - |
| | | LABOR | SO | (37,251,967) | (15,600,768) | (2,691,958) | (14,666,558) | (110,952) | - | (2,523,368) | (738,293) | (920,070) | - |
| | | P | SE | (503,748) | (503,748) | - | - | - | - | - | - | - | - |
| | | G-SG | SG | (40,155) | (15,973) | (24,182) | - | - | - | - | - | - | - |
| | | G-SG | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | (178,830,195) | (33,179,743) | (28,265,424) | (106,452,983) | (1,139,811) | - | (3,620,682) | (4,664,367) | (1,507,185) | - |
| 108MP | Mining Plant Accumulated Depr. | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 108MP | Less Centralia Situs Depreciation | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 1081390 | Accum Depr - Capital Lease | | | | | | | | | | | | |
| | | LABOR | SO | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| | Remove Capital Leases | | | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| 1081399 | Accum Depr - Capital Lease | | | | | | | | | | | | |
| | | P | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| | Remove Capital Leases | | | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| **TOTAL GENERAL PLANT ACCUM DEPR** | | | | **(178,830,195)** | **(33,179,743)** | **(28,265,424)** | **(106,452,983)** | **(1,139,811)** | **-** | **(3,620,682)** | **(4,664,367)** | **(1,507,185)** | **-** |
| **TOTAL ACCUM DEPR - PLANT IN SERVICE** | | | | **(4,043,129,802)** | **(2,063,552,941)** | **(670,080,406)** | **(1,249,778,570)** | **(15,913,181)** | **-** | **(3,620,682)** | **(38,676,837)** | **(1,507,185)** | **-** |

| FERC ACCT | DESCRIPTION | BUSINESS FUNCTION | JAM FACTOR | Total $ | Production | Transmission | Distribution | Dist-Lighting | Ancillary | C_Billing | C_Metering | C_Service | DSM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 111OP | Accum Prov for Amort-Steam | | | | | | | | | | | | |
| | | P | S | (198,109) | (198,109) | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | (198,109) | (198,109) | - | - | - | - | - | - | - | - |
| 111GP | Accum Prov for Amort-General | | | | | | | | | | | | |
| | | D_SPLIT | S | (5,273,651) | - | - | (5,003,544) | (56,086) | - | - | (214,022) | - | - |
| | | CSS_SYS | CN | - | - | - | - | - | - | - | - | - | - |
| | | I-SG | SG | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SO | (412,712) | (172,840) | (29,824) | (162,490) | (1,229) | - | (27,956) | (8,179) | (10,193) | - |
| | | P | SE | - | - | - | - | - | - | - | - | - | - |
| | | | | (5,686,363) | (172,840) | (29,824) | (5,166,033) | (57,315) | - | (27,956) | (222,201) | (10,193) | - |
| 111HP | Accum Prov for Amort-Hydro | | | | | | | | | | | | |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | (1,138,696) | (1,138,696) | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | | | (1,138,696) | (1,138,696) | - | - | - | - | - | - | - | - |
| 111IP | Accum Prov for Amort-Intangible Plant | | | | | | | | | | | | |
| | | I-SITUS | S | (159,409) | - | (103,996) | (53,831) | - | - | - | (1,581) | - | - |
| | | I-DGP | SG | - | - | - | - | - | - | - | - | - | - |
| | | I-DGU | SG | (113,451) | (113,451) | - | - | - | - | - | - | - | - |
| | | P | SE | (770) | (770) | - | - | - | - | - | - | - | - |
| | | I-SG | SG | (31,378,917) | (19,950,608) | (11,428,309) | - | - | - | - | - | - | - |
| | | I-SG | SG | (13,378,910) | (8,506,265) | (4,872,645) | - | - | - | - | - | - | - |
| | | I-SG | SG | (1,777,279) | (1,129,988) | (647,291) | - | - | - | - | - | - | - |
| | | CUST | CN | (63,528,158) | - | - | - | - | - | (28,164,150) | (14,823,237) | (20,540,771) | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | PTD | SO | (112,405,320) | (44,998,923) | (35,592,756) | (31,813,641) | - | - | - | - | - | - |
| | | | | (222,742,214) | (74,700,005) | (52,644,997) | (31,867,472) | - | - | (28,164,150) | (14,824,818) | (20,540,771) | - |
| 111IP | Less Non-Utility Plant | | | | | | | | | | | | |
| | | NUTIL | OTH | - | - | - | - | - | - | - | - | - | - |
| | | | | (222,742,214) | (74,700,005) | (52,644,997) | (31,867,472) | - | - | (28,164,150) | (14,824,818) | (20,540,771) | - |
| 111390 | Accum Amtr - Capital Lease | | | | | | | | | | | | |
| | | LABOR | S | - | - | - | - | - | - | - | - | - | - |
| | | P | SG | - | - | - | - | - | - | - | - | - | - |
| | | LABOR | SO | - | - | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - | - | - |
| | Remove Capital Lease Amtr | | | - | - | - | - | - | - | - | - | - | - |
| **TOTAL ACCUM PROV FOR AMORTIZATION** | | | | **(229,765,382)** | **(76,209,650)** | **(52,674,821)** | **(37,033,505)** | **(57,315)** | **-** | **(28,192,106)** | **(15,047,019)** | **(20,550,964)** | **-** |

Docket No. UE 433
Exhibit PAC/3503
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Robert M. Meredith**

**Updated Oregon Marginal Cost of Service Study Summary**

**July 2024**

STATE OF OREGON
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
12 Months Ended December 31, 2025 Forecast
(Dollars in 000s)

| Line | Class / Function | (A) Total | (B) Residential (sec) | (C) General Service - Schedule 23 0-15 kW (sec) | (D) 15+ kW (sec) | (E) Primary (pri) | (F) General Service - Schedule 28 0-50 kW (sec) | (G) 51-100 kW (sec) | (H) 100 + kW (sec) | (I) Primary (pri) | (J) General Service - Schedule 30 0-300 kW (sec) | (K) 300+ kW (sec) | (L) Primary (pri) | (M) Large Power Service - Schedule 48 1 - 4 MW (sec) | (N) 1 - 4 MW (pri) | (O) > 4 MW (sec) | (P) > 4 MW (pri) | (Q) Trn (trn) | (R) Irrg - Sch 41 (sec) | (S) Lighting Sch 15, 51, 53, 54 (sec) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Demand Related Marginal Cost | | | | | | | | | | | | | | | | | | | |
| 2 | Generation | $387,945 | $173,284 | $14,450 | $15,521 | $47 | $11,024 | $16,726 | $23,923 | $512 | $4,249 | $26,041 | $1,791 | $10,632 | $11,766 | $2,404 | $34,194 | $36,085 | $5,298 | $0 |
| 3 | Transmission | $17,107 | $7,641 | $637 | $684 | $2 | $486 | $738 | $1,055 | $23 | $187 | $1,148 | $79 | $469 | $519 | $106 | $1,508 | $1,591 | $234 | $0 |
| 4 | Distribution | $188,280 | $100,373 | $10,513 | $10,427 | $28 | $5,895 | $9,095 | $12,626 | $240 | $1,796 | $10,657 | $704 | $6,202 | $6,609 | $393 | $4,674 | $0 | $8,013 | $35 |
| 5 | Poles | $52,669 | $27,673 | $3,073 | $3,320 | $10 | $1,675 | $2,512 | $3,530 | $74 | $440 | $2,575 | $183 | $2,081 | $2,315 | $0 | $0 | $0 | $3,204 | $3 |
| 6 | Conductor | $67,334 | $36,681 | $3,571 | $3,859 | $12 | $2,160 | $3,239 | $4,551 | $96 | $654 | $3,873 | $273 | $2,408 | $2,679 | $0 | $0 | $0 | $3,276 | $4 |
| 7 | Substations | $52,875 | $27,639 | $2,059 | $2,225 | $7 | $1,585 | $2,376 | $3,338 | $70 | $596 | $3,595 | $248 | $1,451 | $1,614 | $329 | $4,674 | $0 | $1,070 | $0 |
| 8 | Transformers | $15,402 | $8,380 | $1,811 | $1,024 | $0 | $475 | $968 | $1,207 | $0 | $106 | $614 | $0 | $262 | $0 | $65 | $0 | $0 | $463 | $28 |
| 9 | Total Demand | $781,612 | $381,671 | $36,113 | $37,060 | $105 | $23,301 | $35,653 | $50,229 | $1,016 | $8,028 | $48,503 | $3,278 | $23,504 | $25,502 | $3,297 | $45,050 | $37,676 | $21,558 | $69 |
| 10 | | | | | | | | | | | | | | | | | | | | |
| 11 | | | | | | | | | | | | | | | | | | | | |
| 12 | Energy Related Marginal Cost | | | | | | | | | | | | | | | | | | | |
| 13 | Generation | $1,083,656 | $542,189 | $206,817 | $19,848 | $21,613 | $66 | $15,198 | $23,451 | $34,365 | $755 | $6,099 | $38,658 | $2,737 | $16,298 | $29,283 | $4,040 | $47,560 | $66,284 | $8,394 |
| 14 | Transmission | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 15 | Total Energy | $1,083,656 | $542,189 | $206,817 | $19,848 | $21,613 | $66 | $15,198 | $23,451 | $34,365 | $755 | $6,099 | $38,658 | $2,737 | $16,298 | $29,283 | $4,040 | $47,560 | $66,284 | $8,394 |
| 16 | | | | | | | | | | | | | | | | | | | | |
| 17 | Customer Related Marginal Cost | | | | | | | | | | | | | | | | | | | |
| 18 | Poles | $63,079 | $47,395 | $10,070 | $2,146 | $7 | $451 | $359 | $223 | $6 | $13 | $38 | $3 | $11 | $8 | $0 | $0 | $0 | $2,350 | $0 |
| 19 | Conductor | $27,412 | $20,596 | $4,376 | $933 | $3 | $196 | $156 | $97 | $2 | $6 | $17 | $1 | $5 | $3 | $0 | $0 | $0 | $1,022 | $0 |
| 20 | Transformers | $103,530 | $61,630 | $17,838 | $4,783 | $0 | $4,023 | $3,588 | $2,426 | $0 | $252 | $765 | $0 | $100 | $0 | $5 | $0 | $0 | $8,119 | $0 |
| 21 | Service Drops | $57,215 | $42,311 | $7,975 | $3,175 | $0 | $969 | $788 | $1,114 | $0 | $70 | $536 | $0 | $262 | $0 | $13 | $0 | $0 | $0 | $0 |
| 22 | Meters | $16,604 | $12,531 | $1,835 | $444 | $85 | $151 | $128 | $463 | $100 | $41 | $123 | $69 | $21 | $101 | $1 | $42 | $208 | $258 | $3 |
| 23 | Meter Reading | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 24 | Billing & Collections | $16,127 | $12,891 | $2,067 | $440 | $1 | $157 | $125 | $77 | $2 | $7 | $20 | $1 | $23 | $17 | $1 | $7 | $2 | $96 | $191 |
| 25 | Uncollectables | $6,677 | $5,875 | $124 | $26 | $0 | $85 | $68 | $42 | $1 | $23 | $71 | $5 | $119 | $86 | $6 | $36 | $12 | $99 | $0 |
| 26 | Customer Service / Other | $6,655 | $5,489 | $745 | $159 | $1 | $52 | $42 | $26 | $1 | $3 | $9 | $1 | $6 | $4 | $0 | $2 | $1 | $38 | $77 |
| 27 | Total Customer (Commitment & Billing) | $297,299 | $208,718 | $45,030 | $12,106 | $97 | $6,085 | $5,253 | $4,468 | $112 | $415 | $1,580 | $80 | $546 | $219 | $26 | $86 | $223 | $11,983 | $271 |
| 28 | | | | | | | | | | | | | | | | | | | | |
| 29 | | | | | | | | | | | | | | | | | | | | |
| 30 | Total Revenue @ Full MC | | | | | | | | | | | | | | | | | | | |
| 31 | Generation | $930,134 | $380,101 | $34,298 | $37,134 | $113 | $26,222 | $40,177 | $58,288 | $1,267 | $10,348 | $64,699 | $4,528 | $26,930 | $41,049 | $6,443 | $81,753 | $102,369 | $13,692 | $723 |
| 32 | Transmission | $17,107 | $7,641 | $637 | $684 | $2 | $486 | $738 | $1,055 | $23 | $187 | $1,148 | $79 | $469 | $519 | $106 | $1,508 | $1,591 | $234 | $0 |
| 33 | Distribution | $439,517 | $272,305 | $50,772 | $21,463 | $38 | $11,535 | $13,986 | $16,485 | $249 | $2,137 | $12,013 | $708 | $6,580 | $6,621 | $411 | $4,674 | $0 | $19,505 | $35 |
| 34 | Customer - Billing | $22,804 | $18,766 | $2,191 | $467 | $2 | $242 | $192 | $119 | $3 | $30 | $91 | $6 | $142 | $103 | $7 | $43 | $14 | $195 | $191 |
| 35 | Customer - Metering | $16,604 | $12,531 | $1,835 | $444 | $85 | $151 | $128 | $463 | $100 | $41 | $123 | $69 | $21 | $101 | $1 | $42 | $208 | $258 | $3 |
| 36 | Customer - Other | $6,655 | $5,489 | $745 | $159 | $1 | $52 | $42 | $26 | $1 | $3 | $9 | $1 | $6 | $4 | $0 | $2 | $1 | $38 | $77 |
| 37 | Revenue | $1,432,820 | $696,833 | $90,478 | $60,351 | $240 | $38,689 | $55,262 | $76,437 | $1,642 | $12,746 | $78,084 | $5,391 | $34,147 | $48,396 | $6,969 | $88,022 | $104,183 | $33,922 | $1,028 |

Docket No. UE 433
Exhibit PAC/3504
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Robert M. Meredith**

**Updated Unbundled Revenue Requirement Allocation**

**July 2024**

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
December 31, 2025 Unbundled Revenue Requirement Allocation by Load Class

| Line | Description | Total | (A) Residential (sec) | (B) General Service Sch 23 (sec) | (C) Sch 23 (pri) | (D) General Service Sch 28 (sec) | (E) Sch 28 (pri) | (F) General Service Sch 30 (sec) | (G) Sch 30 (pri) | (H) Large Power Service Sch 48 (sec) | (I) Sch 48 (pri) | (J) (trn) | (K) Irrigation Sch 41 (sec) | (L) Lighting Schs 15, 51, 53, and 54 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Total Operating Revenues | $1,670,831 | $786,075 | $159,656 | $230 | $209,460 | $1,874 | $112,053 | $6,920 | $51,960 | $169,230 | $136,366 | $32,687 | $4,319 |
| 2 | MWh | 15,276,984 | 5,787,620 | 1,160,255 | 1,877 | 2,043,261 | 21,451 | 1,252,474 | 77,805 | 570,908 | 2,171,323 | 1,934,880 | 234,910 | 20,221 |
| 3 | | | | | | | | | | | | | | |
| 4 | Functionalized 20 Year Full Marginal Costs - Class $ | | | | | | | | | | | | | |
| 5 | Generation | $930,134 | $380,101 | $71,432 | $113 | $124,687 | $1,267 | $75,047 | $4,528 | $33,373 | $122,802 | $102,369 | $13,692 | $723 |
| 6 | Transmission | $17,107 | $7,641 | $1,322 | $2 | $2,279 | $23 | $1,336 | $79 | $575 | $2,027 | $1,591 | $234 | $0 |
| 7 | Distribution | $439,517 | $272,305 | $72,235 | $38 | $42,007 | $249 | $14,150 | $708 | $6,991 | $11,295 | $0 | $19,505 | $35 |
| 8 | Customer - Billing | $22,804 | $18,766 | $2,658 | $2 | $553 | $3 | $122 | $6 | $149 | $145 | $14 | $195 | $191 |
| 9 | Customer - Metering | $16,604 | $12,531 | $2,279 | $85 | $742 | $100 | $164 | $69 | $22 | $142 | $208 | $258 | $3 |
| 10 | Customer - Other | $6,655 | $5,489 | $904 | $1 | $120 | $1 | $12 | $1 | $6 | $6 | $1 | $38 | $77 |
| 11 | Total | $1,432,820 | $696,833 | $150,830 | $240 | $170,388 | $1,642 | $90,829 | $5,391 | $41,116 | $136,418 | $104,183 | $33,922 | $1,028 |
| 12 | | | | | | | | | | | | | | |
| 13 | Functional Revenue Requirement Allocation Factors | | | | | | | | | | | | | |
| 14 | Functionalized 20 Year Full Marginal Costs - Class % of Total | | | | | | | | | | | | | |
| 15 | Generation | 100.00% | 40.87% | 7.68% | 0.01% | 13.41% | 0.14% | 8.07% | 0.49% | 3.59% | 13.20% | 11.01% | 1.47% | 0.08% |
| 16 | Transmission | 100.00% | 44.67% | 7.73% | 0.01% | 13.32% | 0.13% | 7.81% | 0.46% | 3.36% | 11.85% | 9.30% | 1.37% | 0.00% |
| 17 | Distribution | 100.00% | 61.96% | 16.44% | 0.01% | 9.56% | 0.06% | 3.22% | 0.16% | 1.59% | 2.57% | 0.00% | 4.44% | 0.01% |
| 18 | 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% |
| 19 | Ancillary Service | 100.00% | 40.87% | 7.68% | 0.01% | 13.41% | 0.14% | 8.07% | 0.49% | 3.59% | 13.20% | 11.01% | 1.47% | 0.08% |
| 20 | Customer - Billing | 100.00% | 82.29% | 11.66% | 0.01% | 2.42% | 0.01% | 0.53% | 0.03% | 0.65% | 0.64% | 0.06% | 0.86% | 0.84% |
| 21 | Customer - Metering | 100.00% | 75.47% | 13.73% | 0.51% | 4.47% | 0.60% | 0.99% | 0.42% | 0.13% | 0.86% | 1.26% | 1.56% | 0.02% |
| 22 | Customer - Other | 100.00% | 82.48% | 13.58% | 0.01% | 1.80% | 0.01% | 0.18% | 0.01% | 0.10% | 0.09% | 0.01% | 0.58% | 1.15% |
| 23 | Embedded DSM - (MWh) | 100.00% | 37.88% | 7.59% | 0.01% | 13.37% | 0.14% | 8.20% | 0.51% | 3.74% | 14.21% | 12.67% | 1.54% | 0.13% |
| 24 | Regulatory & Franchise - (Total Operating Revenues) | 100.00% | 47.05% | 9.56% | 0.01% | 12.54% | 0.11% | 6.71% | 0.41% | 3.11% | 10.13% | 8.16% | 1.96% | 0.26% |
| 25 | | | | | | | | | | | | | | |
| 26 | | | | | | | | | | | | | | |
| 27 | Functionalized Class Revenue Requirement - (Target) | | | | | | | | | | | | | |
| 28 | Generation | $933,960 | $381,664 | $71,726 | $113 | $125,200 | $1,272 | $75,355 | $4,546 | $33,510 | $123,307 | $102,790 | $13,748 | $726 |
| 29 | Transmission | $311,145 | $138,979 | $24,038 | $38 | $41,443 | $411 | $24,294 | $1,436 | $10,455 | $36,861 | $28,941 | $4,249 | $0 |
| 30 | Distribution | $399,925 | $247,776 | $65,728 | $35 | $38,223 | $226 | $12,875 | $644 | $6,361 | $10,277 | $0 | $17,748 | $31 |
| 31 | Distribution Lighting | $3,181 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $3,181 |
| 32 | Distribution Total | $403,106 | $247,776 | $65,728 | $35 | $38,223 | $226 | $12,875 | $644 | $6,361 | $10,277 | $0 | $17,748 | $3,212 |
| 33 | Ancillary Services | $23,960 | $9,791 | $1,840 | $3 | $3,212 | $33 | $1,933 | $117 | $860 | $3,163 | $2,637 | $353 | $19 |
| 34 | Customer - Billing | $24,513 | $20,173 | $2,858 | $2 | $594 | $3 | $131 | $7 | $160 | $156 | $15 | $210 | $206 |
| 35 | Customer - Metering | $18,687 | $14,104 | $2,565 | $95 | $835 | $112 | $184 | $78 | $25 | $160 | $235 | $291 | $3 |
| 36 | Customer - Other | $9,126 | $7,527 | $1,239 | $1 | $165 | $1 | $17 | $1 | $9 | $9 | $1 | $53 | $105 |
| 37 | Embedded DSM - (MWh) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 38 | Franchise Fees | $47,745 | $22,463 | $4,562 | $7 | $5,985 | $54 | $3,202 | $198 | $1,485 | $4,836 | $3,897 | $934 | $123 |
| 39 | Total | $1,772,243 | $842,477 | $174,556 | $293 | $215,658 | $2,113 | $117,991 | $7,027 | $52,865 | $178,770 | $138,515 | $37,585 | $4,394 |
| 40 | | | | | | | | | | | | | | |
| 41 | Ratio of Operating Revn to Revenue Requirement-(Target) | 94.28% | 93.31% | 91.46% | 78.65% | 97.13% | 88.70% | 94.97% | 98.48% | 98.29% | 94.66% | 98.45% | 86.97% | 98.31% |
| 42 | (Line 1 / Line 39) | | | | | | | | | | | | | |
| 43 | Increase or (Decrease) | $101,412 | $56,402 | $14,900 | $63 | $6,198 | $239 | $5,938 | $107 | $905 | $9,539 | $2,150 | $4,898 | $74 |
| 44 | (Line 39 - Line 1) | | | | | | | | | | | | | |
| 45 | | | | | | | | | | | | | | |
| 46 | | | | | | | | | | | | | | |
| 47 | Percent Increase (Decrease) | 6.07% | 7.18% | 9.33% | 27.15% | 2.96% | 12.74% | 5.30% | 1.55% | 1.74% | 5.64% | 1.58% | 14.98% | 1.72% |
| 48 | (Line 43 / Line 1) | | | | | | | | | | | | | |

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2025 Functionalized Revenue - Earned
($ 000)

| Line No. | Description | A Production | B Transmission | C Distribution | D Dist-Lighting | E Ancillary | F C Billing | G C Metering | I C Other | J Franchise Fees | K Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Earned Functional Revenue Requirement | $920,460 | $269,569 | $368,682 | $2,867 | $24,139 | $23,505 | $17,014 | $8,993 | $45,708 | $1,680,937 |
| 2 | | | | | | | | | | | |
| 3 | Percent of Total | 54.76% | 16.04% | 21.93% | 0.17% | 1.44% | 1.40% | 1.01% | 0.54% | 2.72% | 100.00% |
| 4 | | | | | | | | | | | |
| 5 | Revenue From Classes Included in MC Study | $914,926 | $267,948 | $366,465 | $2,850 | $23,993 | $23,364 | $16,911 | $8,939 | $45,434 | $1,670,831 |
| 6 | | | | | | | | | | | |
| 7 | Other Revenues | | | | | | | | | | |
| 8 | Schedule 4 - Employee Discount | | | | | | | | | | ($445) |
| 9 | Partial Requirements - Sch. 47 pri | | | | | | | | | | $3,850 |
| 10 | Partial Requirements - Sch. 47 trn | | | | | | | | | | $1,198 |
| 11 | Sch 848 | | | | | | | | | | $1,517 |
| 12 | Oregon Direct Access Opt Out Amortization | | | | | | | | | | $1,769 |
| 13 | AGA | | | | | | | | | | $4,071 |
| 14 | Paperless Credit | | | | | | | | | | ($1,855) |
| 15 | Total Oregon Situs Revenue | | | | | | | | | | $1,680,937 |

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2025 Functionalized Revenue - Target
($ 000)

| Line No. | Description | A Production | B Transmission | C Distribution | D Dist-Lighting | E Ancillary | F C Billing | G C Metering | I C Other | J Franchise Fees | K Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Target Functional Revenue Requirement | $940,922 | $313,464 | $402,907 | $3,205 | $24,139 | $24,696 | $18,827 | $9,194 | $48,101 | $1,785,454 | |
| 2 | | | | | | | | | | | | |
| 3 | Percent of Total | 52.70% | 17.56% | 22.57% | 0.18% | 1.35% | 1.38% | 1.05% | 0.51% | 2.69% | 100.00% | |
| 4 | | | | | | | | | | | | Increase |
| 5 | Revenue From Classes Included in MC Study | $933,960 | $311,145 | $399,925 | $3,181 | $23,960 | $24,513 | $18,687 | $9,126 | $47,745 | $1,772,243 | $101,412 |
| 6 | | | | | | | | | | | | |
| 7 | Other Revenues | | | | | | | | | | | $104,516 |
| 8 | Schedule 4 - Employee Discount | | | | | | | | | | ($475) | ($30) |
| 9 | Partial Requirements - Sch. 47 pri | | | | | | | | | | $4,444 | $594 |
| 10 | Partial Requirements - Sch. 47 trn | | | | | | | | | | $1,505 | $306 |
| 11 | Sch 848 | | | | | | | | | | $3,752 | $2,234 |
| 12 | Oregon Direct Access Opt Out Amortization | | | | | | | | | | $1,769 | $0 |
| 13 | AGA | | | | | | | | | | $4,071 | $0 |
| 14 | Paperless Credit | | | | | | | | | | ($1,855) | $0 |
| 15 | Total Oregon Situs Revenue | | | | | | | | | | $1,785,453 | |

PACIFICORP
State of Oregon
December 31, 2025 Unbundled Revenue Requirement Allocation by Load Class
FERC Transmission Revenue ($ 000)

| | | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line | Description | Total | Residential (sec) | General Service Schedule 23 (sec) | (pri) | General Service Schedule 28 (sec) | (pri) | General Service Schedule 30 (sec) | (pri) | Large Power Service Schedule 48 (sec) | (pri) | (trn) | Schedule 41 Irrigation | Lighting (sec) |
| 1 | Total Transmission Revenue Requirement | $311,145 | $138,979 | $24,038 | $38 | $41,443 | $411 | $24,294 | $1,436 | $10,455 | $36,861 | $28,941 | $4,249 | $0 |
| 2 | | | | | | | | | | | | | | |
| 3 | FERC Transmission | | | | | | | | | | | | | |
| 4 | Peak MW @ Input | 2,579 | 1,107 | 192 | 99 | 330 | 3 | 194 | 11 | 83 | 294 | 231 | 34 | 1 |
| 5 | % of Total | | 42.94% | 7.43% | 3.85% | 12.80% | 0.13% | 7.51% | 0.44% | 3.23% | 11.39% | 8.94% | 1.31% | 0.04% |
| 6 | FERC Transmission Revenues ($ 000) | $91,066 | $39,102 | $6,763 | $3,502 | $11,660 | $116 | $6,835 | $404 | $2,942 | $10,371 | $8,143 | $1,195 | $33 |
| 7 | | | | | | | | | | | | | | |
| 8 | Other Transmission Revenue Requirement | $220,079 | $99,877 | $17,275 | ($3,465) | $29,783 | $295 | $17,459 | $1,032 | $7,513 | $26,490 | $20,799 | $3,053 | ($33) |

| | OR CP (MW) |
|---|---|
| Jan | 2,814 |
| Feb | 2,631 |
| Mar | 2,502 |
| Apr | 2,365 |
| May | 1,993 |
| Jun | 2,319 |
| Jul | 2,745 |
| Aug | 2,591 |
| Sep | 2,093 |
| Oct | 2,190 |
| Nov | 2,580 |
| Dec | 2,634 |
| Annual Average | 2,455 |

| | |
|---|---|
| Network service rate ($/MW-year)[1] | $37,098 |
| FERC Transmission Revenues | $91,066,068 |

[1]From 2023 Transmission Formula Rate Annual Update p.14

Docket No. UE 433
Exhibit PAC/3505
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Robert M. Meredith**

**Updated Oregon Marginal Cost of Service Study**

**July 2024**

Table 1

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Demand & Energy in Mills/kWh
December 2025 Dollars

| | | | (A) | (B) | (C) | (D) | (E) | (F) |
|---|---|---|---|---|---|---|---|---|
| | | | Energy | | | Demand & Energy | | |
| Line | Description | | 1 Year | 10 Year | 20 Year | 1 Year | 10 Year | 20 Year |
| 1 | Res - Schedule 4 | (sec) | $89.56 | $42.67 | $35.73 | $89.56 | $89.99 | $84.34 |
| 2 | | | | | | | | |
| 3 | GS - Schedule 23 | | | | | | | |
| 4 | 0-15 kW | (sec) | $89.56 | $42.67 | $35.73 | $89.56 | $87.65 | $81.82 |
| 5 | 15+ kW | (sec) | $89.56 | $42.67 | $35.73 | $89.56 | $85.60 | $79.77 |
| 6 | Primary | (pri) | $88.17 | $42.01 | $35.18 | $88.17 | $81.95 | $76.19 |
| 7 | | | | | | | | |
| 8 | GS - Schedule 28 | | | | | | | |
| 9 | 0-50 kW | (sec) | $89.56 | $42.67 | $35.73 | $89.56 | $82.48 | $76.66 |
| 10 | 51-100 kW | (sec) | $89.56 | $42.67 | $35.73 | $89.56 | $82.05 | $76.20 |
| 11 | 100 + kW | (sec) | $89.56 | $42.67 | $35.73 | $89.56 | $80.71 | $74.84 |
| 12 | Primary | (pri) | $88.17 | $42.01 | $35.18 | $88.17 | $77.14 | $71.33 |
| 13 | | | | | | | | |
| 14 | GS - Schedule 30 | | | | | | | |
| 15 | 0-300 kW | (sec) | $89.56 | $42.67 | $35.73 | $89.56 | $78.12 | $72.25 |
| 16 | 300+ kW | (sec) | $89.56 | $42.67 | $35.73 | $89.56 | $76.62 | $70.72 |
| 17 | Primary | (pri) | $88.17 | $42.01 | $35.18 | $88.17 | $74.10 | $68.26 |
| 18 | | | | | | | | |
| 19 | LPS - Schedule 48 | | | | | | | |
| 20 | 1 - 4 MW | (sec) | $89.56 | $42.67 | $35.73 | $89.56 | $79.61 | $73.67 |
| 21 | 1 - 4 MW | (pri) | $88.17 | $5.89 | $35.73 | $88.17 | $28.33 | $58.79 |
| 22 | > 4 MW | (sec) | $89.56 | $304.52 | $35.18 | $89.56 | $328.91 | $60.47 |
| 23 | > 4 MW | (pri) | $88.17 | $42.01 | $35.18 | $88.17 | $70.79 | $65.05 |
| 24 | Trans | (trm) | $85.86 | $40.90 | $34.26 | $85.86 | $62.15 | $53.73 |
| 25 | | | | | | | | |
| 26 | | | | | | | | |
| 27 | Schedule 41- Irrigation | (sec) | $89.56 | $42.67 | $35.73 | $89.56 | $99.36 | $93.39 |
| 28 | | | | | | | | |
| 29 | Lighting | (sec) | $89.56 | $42.67 | $35.73 | $89.56 | $51.35 | $37.44 |

Energy costs include both generation and transmission energy-related costs.

Table 2

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Commitment and Billing in $ / Customer / Month
December 2025 Dollars

| Line | Description | | (A) 1 Year | (B) 10 & 20 Year |
|---|---|---|---|---|
| 1 | Res - Schedule 4 | (sec) | $12.83 | $33.87 |
| 2 | | | | |
| 3 | GS - Schedule 23 | | | |
| 4 | 0-15 kW | (sec) | $14.99 | $52.94 |
| 5 | 15+ kW | (sec) | $23.42 | $66.79 |
| 6 | Primary | (pri) | $168.04 | $161.60 |
| 7 | | | | |
| 8 | GS - Schedule 28 | | | |
| 9 | 0-50 kW | (sec) | $25.46 | $109.53 |
| 10 | 51-100 kW | (sec) | $26.01 | $118.85 |
| 11 | 100 + kW | (sec) | $62.80 | $162.90 |
| 12 | Primary | (pri) | $146.46 | $158.11 |
| 13 | | | | |
| 14 | GS - Schedule 30 | | | |
| 15 | 0-300 kW | (sec) | $73.31 | $172.82 |
| 16 | 300+ kW | (sec) | $104.53 | $217.32 |
| 17 | Primary | (pri) | $155.00 | $162.79 |
| 18 | | | | |
| 19 | LPS - Schedule 48 | | | |
| 20 | 1 - 4 MW | (sec) | $438.26 | $555.93 |
| 21 | 1 - 4 MW | (pri) | $291.42 | $307.56 |
| 22 | > 4 MW | (sec) | $438.26 | $539.79 |
| 23 | > 4 MW | (pri) | $291.42 | $291.42 |
| 24 | Trans | (trn) | $2,322.00 | $2,322.00 |
| 25 | | | | |
| 26 | | | | |
| 27 | Schedule 41- Irrigation | (sec) | $8.61 | $130.03 |
| 28 | | | | |
| 29 | Lighting | (sec) | $5.16 | $35.81 |

Footnote:
Short-run commitment and billing costs include the cost of metering, meter overhead, maintenance, service drops, service drop overhead and maintenance, customer accounting, informational expenses, and billing expenses.

Table 3

PacifiCorp
Oregon Marginal Cost Study
20 Year Marginal Cost
December 2025 Dollars

| Line | Calculation Component | Class | Units Description / Function | Total | (A) Residential (sec) | (B) General Service - Schedule 23 0-15 kW (sec) | (C) 15+ kW (sec) | (D) Primary (pri) | (E) General Service - Schedule 28 0-50 kW (sec) | (F) 51-100 kW (sec) | (G) 100 + kW (sec) | (H) Primary (pri) | (I) General Service - Schedule 30 0-300 kW (sec) | (J) 300+ kW (sec) | (K) Primary (pri) | (L) Large Power Service - Schedule 48 1 - 4 MW (sec) | (M) 1 - 4 MW (pri) | (N) > 4 MW (sec) | (O) > 4 MW (pri) | (P) Trn (trn) | (Q) Irrg - Sch 41 (sec) | (R) Lighting Schs 15, 51, 53, 54 (sec) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Units | Demand | Peak MW @ Input-System | | 1,107 | 92 | 99 | 0 | 70 | 107 | 153 | 3 | 27 | 166 | 11 | 68 | 75 | 15 | 219 | 231 | 34 | 1 |
| 2 | Units | Demand | Peak MW @ Input-Distribution | | 1,316 | 98 | 106 | 0 | 75 | 113 | 159 | 3 | 28 | 171 | 12 | 69 | 77 | 16 | 223 | - | 51 | 0 |
| 3 | Units | Demand | Peak MW @ Input-Transformer | | 3,665 | 792 | 448 | - | 208 | 423 | 528 | - | 46 | 268 | - | 114 | - | 28 | - | - | 203 | 12 |
| 4 | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Units | Energy | Annual MWh @ Input | | 6,248,604 | 599,673 | 652,997 | 1,995 | 459,186 | 708,531 | 1,038,290 | 22,801 | 184,262 | 1,167,972 | 82,702 | 492,415 | 884,743 | 122,047 | 1,436,937 | 2,002,659 | 253,620 | 21,832 |
| 6 | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Units | Customer | Average | | 513,581 | 70,880 | 15,103 | 50 | 4,630 | 3,683 | 2,286 | 59 | 200 | 606 | 41 | 82 | 59 | 4 | 25 | 8 | 3,311 | 7,437 |
| 8 | Units | Customer | Annual - Metered | | 513,581 | 70,880 | 15,103 | 50 | 4,630 | 3,683 | 2,286 | 59 | 200 | 606 | 41 | 82 | 59 | 4 | 25 | 8 | 7,887 | 98 |
| 9 | | | | | | | | | | | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | | | | | | | | | | | |
| 11 | $/Unit | Demand | Generation ($/System Peak kW) | | $156.48 | $156.48 | $156.48 | $156.48 | $156.48 | $156.48 | $156.48 | $156.48 | $156.48 | $156.48 | $156.48 | $156.48 | $156.48 | $156.48 | $156.48 | $156.48 | $156.48 | $156.48 |
| 12 | $/Unit | Demand | Transmission ($/System Peak kW) | | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $0.00 |
| 13 | $/Unit | Demand | Dist-Poles ($/Dist. kW) | | $21.03 | $31.35 | $31.35 | $31.35 | $22.21 | $22.21 | $22.21 | $22.21 | $15.51 | $15.04 | $15.51 | $30.13 | $30.13 | $0.00 | $0.00 | $0.00 | $62.91 | $31.35 |
| 14 | $/Unit | Demand | Dist-Cond ($/Dist. kW) | | $27.88 | $36.44 | $36.44 | $36.44 | $28.63 | $28.63 | $28.63 | $28.63 | $23.07 | $22.63 | $23.07 | $34.87 | $34.87 | $0.00 | $0.00 | $0.00 | $64.30 | $36.44 |
| 15 | $/Unit | Demand | Dist-Substation ($/Dist. kW) | | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $0.00 | $21.01 | $0.00 |
| 16 | $/Unit | Demand | Dist-Transformers ($/Xfmr kW) | | $2.29 | $2.29 | $2.29 | $0.00 | $2.29 | $2.29 | $2.29 | $0.00 | $2.29 | $2.29 | $0.00 | $2.29 | $0.00 | $2.29 | $0.00 | $0.00 | $2.29 | $2.29 |
| 17 | | | | | | | | | | | | | | | | | | | | | | |
| 18 | $/Unit | Energy | Generation Energy @ Input ($/kWh) | | $0.03310 | $0.03310 | $0.03310 | $0.03310 | $0.03310 | $0.03310 | $0.03310 | $0.03310 | $0.03310 | $0.03310 | $0.03310 | $0.03310 | $0.03310 | $0.03310 | $0.03310 | $0.03310 | $0.03310 | $0.03310 |
| 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 | $0.00000 |
| 20 | | | | | | | | | | | | | | | | | | | | | | |
| 21 | $/Unit | Customer | Dist-Poles ($/Customer) | | $92.28 | $142.07 | $142.07 | $142.07 | $97.46 | $97.46 | $97.46 | $97.46 | $65.13 | $62.79 | $65.13 | $134.94 | $134.94 | $0.00 | $0.00 | $0.00 | $298.01 | $142.07 |
| 22 | $/Unit | Customer | Dist-Conductor ($/Customer) | | $40.10 | $61.74 | $61.74 | $61.74 | $42.35 | $42.35 | $42.35 | $42.35 | $28.31 | $27.28 | $28.31 | $58.65 | $58.65 | $0.00 | $0.00 | $0.00 | $129.52 | $61.74 |
| 23 | $/Unit | Customer | Dist-Transformers ($/Customer) | | $120.00 | $251.66 | $316.66 | $0.00 | $868.96 | $974.27 | $1,061.32 | $0.00 | $1,260.01 | $1,263.43 | $0.00 | $1,218.37 | $0.00 | $1,218.37 | $0.00 | $0.00 | $1,029.44 | $163.97 |
| 24 | $/Unit | Customer | Dist-Service Drop ($/Customer) | | $82.38 | $112.52 | $210.25 | $0.00 | $209.38 | $214.00 | $487.49 | $0.00 | $351.35 | $885.25 | $0.00 | $3,198.62 | $0.00 | $3,198.62 | $0.00 | $0.00 | $0.00 | $0.00 |
| 25 | $/Unit | Customer | Meters ($/Customer) | | $24.40 | $25.89 | $29.39 | $1,693.99 | $32.69 | $34.64 | $202.63 | $1,693.99 | $202.97 | $203.06 | $1,693.99 | $257.45 | $1,693.99 | $257.45 | $1,693.99 | $26,060.93 | $32.77 | $25.89 |
| 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 | $0.00 |
| 27 | $/Unit | Customer | Billing & Collections ($/Customer) | | $25.10 | $29.16 | $29.16 | $29.16 | $33.83 | $33.83 | $33.83 | $33.83 | $33.83 | $33.83 | $33.83 | $279.41 | $279.41 | $279.41 | $279.41 | $279.41 | $29.14 | $25.72 |
| 28 | $/Unit | Customer | Uncollectables ($/Customer) | | $11.44 | $1.75 | $1.75 | $1.75 | $18.34 | $18.34 | $18.34 | $18.34 | $117.11 | $117.11 | $117.11 | $1,448.51 | $1,448.51 | $1,448.51 | $1,448.51 | $1,448.51 | $29.85 | $0.00 |
| 29 | $/Unit | Customer | Customer Service / Other ($/Customer) | | $10.69 | $10.51 | $10.51 | $10.51 | $11.32 | $11.32 | $11.32 | $11.32 | $15.08 | $15.08 | $15.08 | $75.18 | $75.18 | $75.18 | $75.18 | $75.18 | $11.58 | $10.31 |
| 30 | | | | | | | | | | | | | | | | | | | | | | |
| 31 | | | | | | | | | | | | | | | | | | | | | | |
| 32 | $000 | Demand | Generation | $387,945 | $173,284 | $14,450 | $15,521 | $47 | $11,024 | $16,726 | $23,923 | $512 | $4,249 | $26,041 | $1,791 | $10,632 | $11,766 | $2,404 | $34,194 | $36,085 | $5,298 | $0 |
| 33 | $000 | Demand | Transmission | $17,107 | $7,641 | $637 | $684 | $2 | $486 | $738 | $1,055 | $23 | $187 | $1,148 | $79 | $469 | $519 | $106 | $1,508 | $1,591 | $234 | $0 |
| 34 | $000 | Demand | Dist-Poles | $52,669 | $27,673 | $3,073 | $3,320 | $10 | $1,675 | $2,512 | $3,530 | $74 | $440 | $2,575 | $183 | $2,081 | $2,315 | $0 | $0 | $0 | $3,204 | $3 |
| 35 | $000 | Demand | Dist-Conductor | $67,334 | $36,681 | $3,571 | $3,859 | $12 | $2,160 | $3,239 | $4,551 | $96 | $654 | $3,873 | $273 | $2,408 | $2,679 | $0 | $0 | $0 | $3,276 | $4 |
| 36 | $000 | Demand | Dist-Substations | $52,875 | $27,639 | $2,059 | $2,225 | $7 | $1,585 | $2,376 | $3,338 | $70 | $596 | $3,595 | $248 | $1,451 | $1,614 | $329 | $4,674 | $0 | $1,070 | $0 |
| 37 | $000 | Demand | Dist-Transformers | $15,402 | $8,380 | $1,811 | $1,024 | $0 | $475 | $968 | $1,207 | $0 | $106 | $614 | $0 | $262 | $0 | $65 | $0 | $0 | $463 | $28 |
| 38 | $000 | Demand | Total Demand | $593,332 | $281,298 | $25,600 | $26,633 | $77 | $17,405 | $26,558 | $37,603 | $775 | $6,232 | $37,846 | $2,574 | $17,302 | $18,893 | $2,903 | $40,376 | $37,676 | $13,544 | $35 |
| 39 | | | | | | | | | | | | | | | | | | | | | | |
| 40 | $000 | Energy | Generation | $542,189 | $206,817 | $19,848 | $21,613 | $66 | $15,198 | $23,451 | $34,365 | $755 | $6,099 | $38,658 | $2,737 | $16,298 | $29,283 | $4,040 | $47,560 | $66,284 | $8,394 | $723 |
| 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 | $542,189 | $206,817 | $19,848 | $21,613 | $66 | $15,198 | $23,451 | $34,365 | $755 | $6,099 | $38,658 | $2,737 | $16,298 | $29,283 | $4,040 | $47,560 | $66,284 | $8,394 | $723 |
| 43 | | | | | | | | | | | | | | | | | | | | | | |
| 44 | $000 | Customer | Dist-Poles | $63,079 | $47,395 | $10,070 | $2,146 | $7 | $451 | $359 | $223 | $6 | $13 | $38 | $3 | $11 | $8 | $0 | $0 | $0 | $2,350 | $0 |
| 45 | $000 | Customer | Dist-Conductor | $27,412 | $20,596 | $4,376 | $933 | $3 | $196 | $156 | $97 | $2 | $6 | $17 | $1 | $5 | $3 | $0 | $0 | $0 | $1,022 | $0 |
| 46 | $000 | Customer | Dist-Transformers | $103,530 | $61,630 | $17,838 | $4,783 | $0 | $4,023 | $3,588 | $2,426 | $0 | $252 | $765 | $0 | $100 | $0 | $5 | $0 | $0 | $8,119 | $0 |
| 47 | $000 | Customer | Dist-Service Drop | $57,215 | $42,311 | $7,975 | $3,175 | $0 | $969 | $788 | $1,114 | $0 | $70 | $536 | $0 | $262 | $0 | $13 | $0 | $0 | $0 | $0 |
| 48 | $000 | Customer | Meters | $16,604 | $12,531 | $1,835 | $444 | $85 | $151 | $128 | $463 | $100 | $41 | $123 | $69 | $21 | $101 | $1 | $42 | $208 | $258 | $3 |
| 49 | $000 | Customer | Meter Reading | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 50 | $000 | Customer | Billing & Collections | $16,127 | $12,891 | $2,067 | $440 | $1 | $157 | $125 | $77 | $2 | $7 | $20 | $1 | $23 | $17 | $1 | $7 | $2 | $96 | $191 |
| 51 | $000 | Customer | Uncollectables | $6,677 | $5,875 | $124 | $26 | $0 | $85 | $68 | $42 | $1 | $23 | $71 | $5 | $119 | $86 | $6 | $36 | $12 | $99 | $0 |
| 52 | $000 | Customer | Customer Service / Other | $6,655 | $5,489 | $745 | $159 | $1 | $52 | $42 | $26 | $1 | $3 | $9 | $1 | $6 | $4 | $0 | $2 | $1 | $38 | $77 |
| 53 | $000 | Customer | Total Customer (Commitment & Billing) | $297,299 | $208,718 | $45,030 | $12,106 | $97 | $6,085 | $5,253 | $4,468 | $112 | $415 | $1,580 | $80 | $546 | $219 | $26 | $86 | $223 | $11,983 | $271 |
| 54 | | | | | | | | | | | | | | | | | | | | | | |
| 55 | | | | | | | | | | | | | | | | | | | | | | |
| 56 | | | Total Revenue @ Full MC ($000) | | | | | | | | | | | | | | | | | | | |
| 57 | | | Generation | $930,134 | $380,101 | $34,298 | $37,134 | $113 | $26,222 | $40,177 | $58,288 | $1,267 | $10,348 | $64,699 | $4,528 | $26,930 | $41,049 | $6,443 | $81,753 | $102,369 | $13,692 | $723 |
| 58 | | | Transmission | $17,107 | $7,641 | $637 | $684 | $2 | $486 | $738 | $1,055 | $23 | $187 | $1,148 | $79 | $469 | $519 | $106 | $1,508 | $1,591 | $234 | $0 |
| 59 | | | Distribution | $439,517 | $272,305 | $50,772 | $21,463 | $38 | $11,535 | $13,986 | $16,485 | $249 | $2,137 | $12,013 | $708 | $6,580 | $6,621 | $411 | $4,674 | $0 | $19,505 | $35 |
| 60 | | | Customer - Billing | $22,804 | $18,766 | $2,191 | $467 | $2 | $242 | $192 | $119 | $3 | $30 | $91 | $6 | $142 | $103 | $7 | $43 | $14 | $195 | $191 |
| 61 | | | Customer - Metering | $16,604 | $12,531 | $1,835 | $444 | $85 | $151 | $128 | $463 | $100 | $41 | $123 | $69 | $21 | $101 | $1 | $42 | $208 | $258 | $3 |
| 62 | | | Customer - Other | $6,655 | $5,489 | $745 | $159 | $1 | $52 | $42 | $26 | $1 | $3 | $9 | $1 | $6 | $4 | $0 | $2 | $1 | $38 | $77 |
| 63 | | | Total Revenue | $1,432,820 | $696,833 | $90,478 | $60,351 | $240 | $38,689 | $55,262 | $76,437 | $1,642 | $12,746 | $78,084 | $5,391 | $34,147 | $48,396 | $6,969 | $88,022 | $104,183 | $33,922 | $1,028 |

Table 4

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Generation Costs in Nominal Dollars

| | (B) Energy Only ($/MWh) | (D) Capacity Only ($/kW) |
|---|---|---|
| 2023 (1 Year) | 82.95 | 104.74 |
| 2023 - 2027 (5 Year, Short Run) | 50.62 | 134.10 |
| 2023 - 2032 (10 Year, Medium Run) | 39.52 | 149.78 |
| 2023 - 2042 (20 Year, Long Run) | 33.10 | 156.48 |

Table 5

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost of
Transmission Investment and Associated Expenses

| Line | Item | $ | |
|---|---|---|---|
| 1 | Growth Related Investments - (2024 to 2028 in $000s) | $271,101 | |
| 2 | | | |
| 3 | System Growth MW from 2022 to 2026 | 3,211 | |
| 4 | | | |
| 5 | Marginal Investment (line 1/line 3) | $84.43 | / kW |
| 6 | | | |
| 7 | Annualized Investment @ 6.52% | $5.50 | / kW |
| 8 | Admin. & General Factor @ 0.58% | $0.49 | |
| 9 | Annual O&M Expenses @ 1.080% | $0.91 | / kW |
| 10 | Annualized Marginal Cost | $6.90 | / kW |
| 11 | | | |
| 12 | Marginal Cost of Demand-Related Transmission | $6.90 | / kW |
| 13 | | | |
| 14 | Marginal Cost of Energy-Related Transmission (Line 10 - Line 12) | $0.00 | / kW |
| 15 | Marginal Cost of Energy-Related Transmission | $0.00000 | / kWh |
| 16 | $0.00 / (8760 x 77.88% LF)) | | |

Table 6

PacifiCorp
Oregon Marginal Cost Study
Marginal Distribution & Billing Costs
2025 Dollars

| Line | Description | (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 |
| | | | 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 | Trans | | |
| | | (sec) | (sec) | (sec) | (pri) | (sec) | (sec) | (sec) | (pri) | (sec) | (sec) | (pri) | (sec) | (pri) | (sec) | (pri) | (trn) | (sec) | (sec) |
| 1 | Demand Costs ($/kW) | | | | | | | | | | | | | | | | | | |
| 2 | | | | | | | | | | | | | | | | | | | |
| 3 | Dist-Poles | $14.47 | $21.57 | $21.57 | $21.57 | $15.28 | $15.28 | $15.28 | $15.28 | $10.67 | $10.35 | $10.67 | $20.73 | $20.73 | $0.00 | $0.00 | $0.00 | $43.28 | |
| 4 | Dist-Conductors | $19.18 | $25.07 | $25.07 | $25.07 | $19.70 | $19.70 | $19.70 | $19.70 | $15.87 | $15.57 | $15.87 | $23.99 | $23.99 | $0.00 | $0.00 | $0.00 | $44.24 | |
| 5 | Dist-Substation | $14.45 | $14.45 | $14.45 | $14.45 | $14.45 | $14.45 | $14.45 | $14.45 | $14.45 | $14.45 | $14.45 | $14.45 | $14.45 | $14.45 | $14.45 | $0.00 | $14.45 | $14.45 |
| 6 | Dist. O&M @ 45.35% of Investment | $21.81 | $27.71 | $27.71 | $27.71 | $22.42 | $22.42 | $22.42 | $22.42 | $18.59 | $18.31 | $18.59 | $26.83 | $26.83 | $6.55 | $6.55 | $0.00 | $46.24 | $6.55 |
| 7 | Total $/Dist. kW | $69.92 | $88.80 | $88.80 | $88.80 | $71.85 | $71.85 | $71.85 | $71.85 | $59.58 | $58.68 | $59.58 | $86.01 | $86.01 | $21.01 | $21.01 | $0.00 | $148.22 | $21.01 |
| 8 | | | | | | | | | | | | | | | | | | | |
| 9 | Dist-Transformers | $1.57 | $1.57 | $1.57 | $0.00 | $1.57 | $1.57 | $1.57 | $0.00 | $1.57 | $1.57 | $0.00 | $1.57 | $0.00 | $1.57 | $0.00 | $0.00 | $1.57 | $1.57 |
| 10 | Dist. O&M @ 45.35% of Investment | $0.71 | $0.71 | $0.71 | $0.00 | $0.71 | $0.71 | $0.71 | $0.00 | $0.71 | $0.71 | $0.00 | $0.71 | $0.00 | $0.71 | $0.00 | $0.00 | $0.71 | $0.71 |
| 11 | Total $/Transformer kW | $2.29 | $2.29 | $2.29 | $0.00 | $2.29 | $2.29 | $2.29 | $0.00 | $2.29 | $2.29 | $0.00 | $2.29 | $0.00 | $2.29 | $0.00 | $0.00 | $2.29 | $2.29 |
| 12 | | | | | | | | | | | | | | | | | | | |
| 13 | | | | | | | | | | | | | | | | | | | |
| 14 | | | | | | | | | | | | | | | | | | | |
| 15 | Customer Costs ($/Customer) | | | | | | | | | | | | | | | | | | |
| 16 | | | | | | | | | | | | | | | | | | | |
| 17 | Commitment | | | | | | | | | | | | | | | | | | |
| 18 | Dist-Poles | $63.49 | $97.74 | $97.74 | $97.74 | $67.05 | $67.05 | $67.05 | $67.05 | $44.81 | $43.20 | $44.81 | $92.84 | $92.84 | $0.00 | $0.00 | $0.00 | $205.03 | |
| 19 | Dist-Conductors | $27.59 | $42.48 | $42.48 | $42.48 | $29.14 | $29.14 | $29.14 | $29.14 | $19.48 | $18.77 | $19.48 | $40.35 | $40.35 | $0.00 | $0.00 | $0.00 | $89.11 | |
| 20 | Dist-Transformers | $82.56 | $173.14 | $217.86 | $0.00 | $597.84 | $670.29 | $730.18 | $0.00 | $866.88 | $869.23 | $0.00 | $838.23 | $838.23 | $0.00 | $0.00 | $0.00 | $708.25 | $112.81 |
| 21 | Dist. O&M @ 45.35% of Investment | $78.75 | $142.11 | $162.39 | $63.59 | $314.74 | $347.60 | $374.76 | $43.62 | $422.29 | $422.30 | $29.16 | $440.54 | $440.54 | $0.00 | $0.00 | $0.00 | $454.58 | $51.16 |
| 22 | Total Commitment | $252.39 | $455.47 | $520.47 | $203.81 | $1,008.77 | $1,114.08 | $1,201.13 | $139.81 | $1,353.46 | $1,353.50 | $93.45 | $1,411.96 | $1,411.96 | $0.00 | $0.00 | $0.00 | $1,456.97 | $163.97 |
| 23 | Monthly Commitment | $21.03 | $37.96 | $43.37 | $16.98 | $84.06 | $92.84 | $100.09 | $11.65 | $112.79 | $112.79 | $7.79 | $117.66 | $117.66 | $0.00 | $0.00 | $0.00 | $121.41 | $13.66 |
| 24 | | | | | | | | | | | | | | | | | | | |
| 25 | Billing | | | | | | | | | | | | | | | | | | |
| 26 | Dist-Service Drop | $56.68 | $77.41 | $144.65 | $0.00 | $144.05 | $147.23 | $335.39 | $0.00 | $351.35 | $609.05 | $0.00 | $2,200.63 | $2,200.63 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| 27 | Dist. O&M @ 45.35% of Investment | $25.70 | $35.11 | $65.60 | $0.00 | $65.33 | $66.77 | $152.10 | $0.00 | $159.34 | $276.20 | $0.00 | $997.99 | $997.99 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| 28 | Meter | $16.71 | $17.73 | $20.13 | $1,160.11 | $22.39 | $23.72 | $138.77 | $1,160.11 | $139.00 | $139.06 | $1,160.11 | $176.31 | $1,160.11 | $176.31 | $1,160.11 | $17,847.51 | $22.44 | $17.73 |
| 29 | Meter O&M @ 46.02% of Investment | $7.58 | $8.04 | $9.13 | $526.11 | $10.15 | $10.76 | $62.93 | $526.11 | $63.04 | $63.06 | $526.11 | $79.96 | $526.11 | $79.96 | $526.11 | $8,093.85 | $10.18 | $8.04 |
| 30 | Meter Reading | $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 | $0.00 |
| 31 | Billing & Collections | $29.16 | $29.16 | $29.16 | $29.16 | $33.83 | $33.83 | $33.83 | $33.83 | $33.83 | $33.83 | $33.83 | $279.41 | $279.41 | $279.41 | $279.41 | $279.41 | $29.14 | $25.72 |
| 32 | Uncollectables | $11.44 | $1.75 | $1.75 | $1.75 | $18.34 | $18.34 | $18.34 | $18.34 | $117.11 | $117.11 | $117.11 | $1,448.51 | $1,448.51 | $1,448.51 | $1,448.51 | $1,448.51 | $29.85 | $0.00 |
| 33 | Customer Service / Other | $10.69 | $10.51 | $10.51 | $10.51 | $11.32 | $11.32 | $11.32 | $11.32 | $15.08 | $15.08 | $15.08 | $75.18 | $75.18 | $75.18 | $75.18 | $75.18 | $11.58 | $10.31 |
| 34 | Total Billing | $157.96 | $179.71 | $280.93 | $1,727.65 | $305.41 | $311.97 | $752.68 | $1,749.71 | $878.75 | $1,253.40 | $1,852.24 | $5,257.98 | $6,687.93 | $2,059.36 | $3,489.32 | $27,744.45 | $103.19 | $61.81 |
| 35 | Monthly Billing | $13.16 | $14.98 | $23.41 | $143.97 | $25.45 | $26.00 | $62.72 | $145.81 | $73.23 | $104.45 | $154.35 | $438.17 | $557.33 | $171.61 | $290.78 | $2,312.04 | $8.60 | $5.15 |
| 36 | | | | | | | | | | | | | | | | | | | |
| 37 | Total Customer (Commitment & Billing) | $410.35 | $635.18 | $801.40 | $1,931.46 | $1,314.19 | $1,426.05 | $1,953.81 | $1,889.53 | $2,232.20 | $2,606.90 | $1,945.69 | $6,669.94 | $8,099.89 | $2,059.36 | $3,489.32 | $27,744.45 | $1,560.16 | $225.78 |
| 38 | Monthly Customer (Commitment & Billing) | $34.20 | $52.93 | $66.78 | $160.95 | $109.52 | $118.84 | $162.82 | $157.46 | $186.02 | $217.24 | $162.14 | $555.83 | $674.99 | $171.61 | $290.78 | $2,312.04 | $130.01 | $18.81 |
| 39 | | | | | | | | | | | | | | | | | | | |

Table 7

PacifiCorp
Oregon Marginal Cost Study
20 Year Demand Costs Divided by Billing kW
December 2025 Dollars

| | | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) | (O) | (P) | (Q) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Residential | General Service - Schedule 23 | | | General Service - Schedule 28 | | | | General Service - Schedule 30 | | | Large Power Service - Schedule 48 | | | | | Irrg - Sch 41 | Lighting |
| Line | Units Description / Function | Total | | 0-15 kW | 15+ kW | | 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 | | |
| | | | (sec) | (sec) | (sec) | (pri) | (sec) | (sec) | (sec) | (pri) | (sec) | (sec) | (pri) | (sec) | (pri) | (sec) | (pri) | (trn) | (sec) | (sec) |
| 1 | Marginal Cost ($000) | | | | | | | | | | | | | | | | | | | |
| 2 | | | | | | | | | | | | | | | | | | | | |
| 3 | Generation | $387,945 | $173,284 | $14,450 | $15,521 | $47 | $11,024 | $16,726 | $23,923 | $512 | $4,249 | $26,041 | $1,791 | $10,632 | $11,766 | $2,404 | $34,194 | $36,085 | $5,298 | $0 |
| 4 | Transmission | $17,107 | $7,641 | $637 | $684 | $2 | $486 | $738 | $1,055 | $23 | $187 | $1,148 | $79 | $469 | $519 | $106 | $1,508 | $1,591 | $234 | $0 |
| 5 | Dist-Poles, Wire, Sub | $172,878 | $91,993 | $8,702 | $9,403 | $28 | $5,420 | $8,127 | $11,418 | $240 | $1,690 | $10,043 | $704 | $5,940 | $6,609 | $329 | $4,674 | $0 | $7,550 | $7 |
| 6 | Dist-Transformers | $15,402 | $8,380 | $1,811 | $1,024 | $0 | $475 | $968 | $1,207 | $0 | $106 | $614 | $0 | $262 | $0 | $65 | $0 | $0 | $463 | $28 |
| 7 | | | | | | | | | | | | | | | | | | | | |
| 8 | Average Billing kW @ Sales | $8,989,495 | 5,042,753 | 947,994 | 535,908 | 11,400 | 191,574 | 390,191 | 486,664 | 39,149 | 55,540 | 321,463 | 53,025 | 105,438 | 26,117 | 114,319 | 155,107 | 317,201 | 186,770 | 8,881 |
| 9 | | | | | | | | | | | | | | | | | | | | |
| 10 | Generation ($/kW) | | $34.36 | $2.87 | $3.08 | $0.01 | $2.19 | $3.32 | $4.74 | $0.10 | $0.84 | $5.16 | $0.36 | $2.11 | $2.33 | $0.48 | $6.78 | $7.16 | $1.05 | $0.00 |
| 11 | Transmission ($/kW) | | $1.52 | $0.13 | $0.14 | $0.00 | $0.10 | $0.15 | $0.21 | $0.00 | $0.04 | $0.23 | $0.02 | $0.09 | $0.10 | $0.02 | $0.30 | $0.32 | $0.05 | $0.00 |
| 12 | Dist-Poles, Wire, Sub ($/kW) | | $18.24 | $1.73 | $1.86 | $0.01 | $1.07 | $1.61 | $2.26 | $0.05 | $0.34 | $1.99 | $0.14 | $1.18 | $1.31 | $0.07 | $0.93 | $0.00 | $1.50 | $0.00 |
| 13 | Dist-Transformers ($/kW) | | $1.66 | $0.36 | $0.20 | $0.00 | $0.09 | $0.19 | $0.24 | $0.00 | $0.02 | $0.12 | $0.00 | $0.05 | $0.00 | $0.01 | $0.00 | $0.00 | $0.09 | $0.01 |
| 14 | | | | | | | | | | | | | | | | | | | | |
| 15 | Total Demand Related | | $55.78 | $5.08 | $5.28 | $0.02 | $3.45 | $5.27 | $7.46 | $0.15 | $1.24 | $7.51 | $0.51 | $3.43 | $3.75 | $0.58 | $8.01 | $7.47 | $2.69 | $0.01 |
| 16 | Monthly Demand Related | | $4.65 | $0.42 | $0.44 | $0.00 | $0.29 | $0.44 | $0.62 | $0.01 | $0.10 | $0.63 | $0.04 | $0.29 | $0.31 | $0.05 | $0.67 | $0.62 | $0.22 | $0.00 |

Table 8

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost Percentage
December 2025 Dollars

| Line | Description | (A) Marginal Cost (000s) | (B) Mills / kWh | (C) % of Total |
|---|---|---|---|---|
| 1 | Demand Related Marginal Cost | | | |
| 2 | Generation | $387,945 | 25.39 | 27% |
| 3 | Transmission | $17,107 | 1.12 | 1% |
| 4 | Dist. Poles, Cond., Subst. | $172,878 | 11.32 | 12% |
| 5 | Dist. Transformers | $15,402 | 1.01 | 1% |
| 6 | Total Demand Related | $593,332 | 38.84 | 41% |
| 7 | | | | |
| 8 | Energy Related Marginal Cost | | | |
| 9 | Generation | $542,189 | 35.49 | 38% |
| 10 | Transmission | $0 | - | 0% |
| 11 | Total Energy Related | 542189.1393 | 35.49 | 38% |
| 12 | | | | |
| 13 | Commitment & Billing | | | |
| 14 | Commitment | $194,021 | 12.70 | 14% |
| 15 | Billing | $103,278 | 6.76 | 7% |
| 16 | Total Commitment & Billing | 297299.2168 | 19.46 | 21% |
| 17 | | | | |
| 18 | | | | |
| 19 | TOTAL MARGINAL COST | $1,432,820 | 93.79 | 100% |
| 20 | | | | |
| 21 | | | | |
| 22 | | Note: Total MWh @ Sales = | 15,276,984 | |

10 Year MC

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

| Line | Calculation Component | Class | Units Description / Function | Total | (A) Residential (sec) | (B) General Service - Schedule 23 0-15 kW (sec) | (C) General Service - Schedule 23 15+ kW (sec) | (D) General Service - Schedule 23 Primary (pri) | (E) General Service - Schedule 28 0-50 kW (sec) | (F) General Service - Schedule 28 51-100 kW (sec) | (G) General Service - Schedule 28 100 + kW (sec) | (H) General Service - Schedule 28 Primary (pri) | (I) General Service - Schedule 30 0-300 kW (sec) | (J) General Service - Schedule 30 300+ kW (sec) | (K) General Service - Schedule 30 Primary (pri) | (L) Large Power Service - Schedule 48 1 - 4 MW (sec) | (M) Large Power Service - Schedule 48 1 - 4 MW (pri) | (N) Large Power Service - Schedule 48 > 4 MW (sec) | (O) Large Power Service - Schedule 48 > 4 MW (pri) | (P) Large Power Service - Schedule 48 Trn (trn) | (Q) Irrg - Sch 41 (sec) | (Q) Lighting (sec) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Units | Demand | Peak MW @ Input-System | | 1,107 | 92 | 99 | 0 | 70 | 107 | 153 | 3 | 27 | 166 | 11 | 68 | 75 | 15 | 219 | 231 | 34 | 1 |
| 2 | Units | Demand | Peak MW @ Input-Distribution | | 1,316 | 98 | 106 | 0 | 75 | 113 | 159 | 3 | 28 | 171 | 12 | 69 | 77 | 16 | 223 | 237 | 51 | 0 |
| 3 | Units | Demand | Peak MW @ Input-Transformer | | 3,665 | 792 | 448 | 12 | 208 | 423 | 528 | 42 | 46 | 268 | 57 | 114 | 122 | 28 | 166 | 329 | 203 | 12 |
| 4 | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Units | Energy | Annual MWh @ Input | | 6,248,604 | 599,673 | 652,997 | 1,995 | 459,186 | 708,531 | 1,038,290 | 22,801 | 184,262 | 1,167,972 | 82,702 | 492,415 | 122,047 | 884,743 | 1,436,937 | 2,002,659 | 253,620 | 21,832 |
| 6 | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Units | Customer | Average | | 513,581 | 70,880 | 15,103 | 50 | 4,630 | 3,683 | 2,286 | 59 | 200 | 606 | 41 | 82 | 59 | 4 | 25 | 8 | 3,311 | 7,437 |
| 8 | Units | Customer | Annual - Metered | | 513,581 | 70,880 | 15,103 | 50 | 4,630 | 3,683 | 2,286 | 59 | 200 | 606 | 41 | 82 | 59 | 4 | 25 | 8 | 7,887 | 98 |
| 9 | | | | | | | | | | | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | | | | | | | | | | | |
| 11 | $/Unit | Demand | Generation ($/System Peak kW) | | $ 149.78 | $149.78 | $149.78 | $149.78 | $149.78 | $149.78 | $149.78 | $149.78 | $149.78 | $149.78 | $149.78 | $149.78 | $149.78 | $149.78 | $149.78 | $149.78 | $149.78 | $149.78 |
| 12 | $/Unit | Demand | Transmission ($/System Peak kW) | | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $6.90 | $0.00 |
| 13 | $/Unit | Demand | Dist-Poles ($/Dist. kW) | | $21.03 | $31.35 | $31.35 | $31.35 | $22.21 | $22.21 | $22.21 | $22.21 | $15.51 | $15.04 | $15.51 | $30.13 | $30.13 | $0.00 | $0.00 | $0.00 | $62.91 | $31.35 |
| 14 | $/Unit | Demand | Dist-Cond ($/Dist. kW) | | $27.88 | $36.44 | $36.44 | $36.44 | $28.63 | $28.63 | $28.63 | $28.63 | $23.07 | $22.63 | $23.07 | $34.87 | $34.87 | $0.00 | $0.00 | $0.00 | $64.30 | $36.44 |
| 15 | $/Unit | Demand | Dist-Substation ($/Dist. kW) | | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $21.01 | $0.00 |
| 16 | $/Unit | Demand | Dist-Transformers ($/Xfmr kW) | | $2.29 | $2.29 | $2.29 | $0.00 | $2.29 | $2.29 | $2.29 | $0.00 | $2.29 | $2.29 | $0.00 | $2.29 | $0.00 | $2.29 | $0.00 | $0.00 | $2.29 | $2.29 |
| 17 | | | | | | | | | | | | | | | | | | | | | | |
| 18 | $/Unit | Energy | Generation Energy @ Input ($/kWh) | | $0.03952 | $0.03952 | $0.03952 | $0.03952 | $0.03952 | $0.03952 | $0.03952 | $0.03952 | $0.03952 | $0.03952 | $0.03952 | $0.03952 | $0.03952 | $0.03952 | $0.03952 | $0.03952 | $0.03952 | $0.03952 |
| 19 | | | | | | | | | | | | | | | | | | | | | | |
| 20 | | | | | | | | | | | | | | | | | | | | | | |
| 21 | $/Unit | Customer | Dist-Poles ($/Customer) | | $92.28 | $142.07 | $142.07 | $142.07 | $97.46 | $97.46 | $97.46 | $97.46 | $65.13 | $62.79 | $65.13 | $134.94 | $134.94 | $0.00 | $0.00 | $0.00 | $298.01 | $142.07 |
| 22 | $/Unit | Customer | Dist-Conductor ($/Customer) | | $40.10 | $61.74 | $61.74 | $61.74 | $42.35 | $42.35 | $42.35 | $42.35 | $28.31 | $27.28 | $28.31 | $58.65 | $58.65 | $0.00 | $0.00 | $0.00 | $129.52 | $61.74 |
| 23 | $/Unit | Customer | Dist-Transformers ($/Customer) | | $120.00 | $251.66 | $316.66 | $0.00 | $868.96 | $974.27 | $1,061.32 | $0.00 | $1,260.01 | $1,263.43 | $0.00 | $1,218.37 | $0.00 | $1,218.37 | $0.00 | $0.00 | $1,029.44 | $163.97 |
| 24 | $/Unit | Customer | Dist-Service Drop ($/Customer) | | $82.38 | $112.52 | $210.25 | $0.00 | $209.38 | $214.00 | $487.49 | $0.00 | $351.35 | $885.25 | $0.00 | $3,198.62 | $0.00 | $3,198.62 | $0.00 | $0.00 | $0.00 | $0.00 |
| 25 | $/Unit | Customer | Meters ($/Customer) | | $24.40 | $25.89 | $29.39 | $1,693.99 | $32.69 | $34.64 | $202.63 | $1,693.99 | $202.97 | $203.06 | $1,693.99 | $257.45 | $1,693.99 | $257.45 | $1,693.99 | $26,060.93 | $32.77 | $25.89 |
| 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 | $0.00 |
| 27 | $/Unit | Customer | Billing & Collections ($/Customer) | | $25.10 | $29.16 | $29.16 | $29.16 | $33.83 | $33.83 | $33.83 | $33.83 | $33.83 | $33.83 | $33.83 | $279.41 | $279.41 | $279.41 | $279.41 | $279.41 | $29.14 | $25.72 |
| 28 | $/Unit | Customer | Uncollectables ($/Customer) | | $11.44 | $1.75 | $1.75 | $1.75 | $18.34 | $18.34 | $18.34 | $18.34 | $117.11 | $117.11 | $117.11 | $1,448.51 | $1,448.51 | $1,448.51 | $1,448.51 | $1,448.51 | $29.85 | $0.00 |
| 29 | $/Unit | Customer | Customer Service / Other ($/Customer) | | $10.69 | $10.51 | $10.51 | $10.51 | $11.32 | $11.32 | $11.32 | $11.32 | $15.08 | $15.08 | $15.08 | $75.18 | $75.18 | $75.18 | $75.18 | $75.18 | $11.58 | $10.31 |
| 30 | | | | | | | | | | | | | | | | | | | | | | |
| 31 | | | | | | | | | | | | | | | | | | | | | | |
| 32 | $000 | Demand | Generation | $371,494 | $165,873 | $13,832 | $14,858 | $45 | $10,552 | $16,011 | $22,900 | $491 | $4,067 | $24,928 | $1,714 | $10,177 | $11,262 | $2,301 | $32,731 | $34,542 | $5,071 | $141 |
| 33 | $000 | Demand | Transmission | $17,107 | $7,641 | $637 | $684 | $2 | $486 | $738 | $1,055 | $23 | $187 | $1,148 | $79 | $469 | $519 | $106 | $1,508 | $1,591 | $234 | $0 |
| 34 | $000 | Demand | Dist-Poles | $52,669 | $27,673 | $3,073 | $3,320 | $10 | $1,675 | $2,512 | $3,530 | $74 | $440 | $2,575 | $183 | $2,081 | $2,315 | $0 | $0 | $0 | $3,204 | $3 |
| 35 | $000 | Demand | Dist-Conductor | $67,334 | $36,681 | $3,571 | $3,859 | $12 | $2,160 | $3,239 | $4,551 | $96 | $654 | $3,873 | $273 | $2,408 | $2,679 | $0 | $0 | $0 | $3,276 | $4 |
| 36 | $000 | Demand | Dist-Substations | $57,846 | $27,639 | $2,059 | $2,225 | $7 | $1,585 | $2,376 | $3,338 | $70 | $596 | $3,595 | $248 | $1,451 | $1,614 | $329 | $4,674 | $4,971 | $1,070 | $0 |
| 37 | $000 | Demand | Dist-Transformers | $15,402 | $8,380 | $1,811 | $1,024 | $0 | $475 | $968 | $1,207 | $0 | $106 | $614 | $0 | $262 | $0 | $65 | $0 | $0 | $463 | $28 |
| 38 | $000 | Demand | Total Demand | $581,853 | $273,887 | $24,982 | $25,969 | $75 | $16,934 | $25,843 | $36,580 | $754 | $6,050 | $36,732 | $2,497 | $16,848 | $18,390 | $2,800 | $38,913 | $41,104 | $13,318 | $176 |
| 39 | | | | | | | | | | | | | | | | | | | | | | |
| 40 | $000 | Energy | Generation | $647,396 | $246,948 | $23,699 | $25,807 | $79 | $18,147 | $28,002 | $41,034 | $901 | $7,282 | $46,159 | $3,268 | $19,461 | $4,823 | $34,966 | $56,789 | $79,146 | $10,023 | $863 |
| 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 | $647,396 | $246,948 | $23,699 | $25,807 | $79 | $18,147 | $28,002 | $41,034 | $901 | $7,282 | $46,159 | $3,268 | $19,461 | $4,823 | $34,966 | $56,789 | $79,146 | $10,023 | $863 |
| 43 | | | | | | | | | | | | | | | | | | | | | | |
| 44 | $000 | Customer | Dist-Poles | $63,093 | $47,395 | $10,070 | $2,146 | $7 | $451 | $359 | $223 | $6 | $13 | $38 | $3 | $11 | $8 | $0 | $0 | $0 | $2,350 | $14 |
| 45 | $000 | Customer | Dist-Conductor | $27,418 | $20,596 | $4,376 | $933 | $3 | $196 | $156 | $97 | $2 | $6 | $17 | $1 | $5 | $3 | $0 | $0 | $0 | $1,022 | $6 |
| 46 | $000 | Customer | Dist-Transformers | $103,546 | $61,630 | $17,838 | $4,783 | $0 | $4,023 | $3,588 | $2,426 | $0 | $252 | $765 | $0 | $100 | $0 | $5 | $0 | $0 | $8,119 | $16 |
| 47 | $000 | Customer | Dist-Service Drop | $57,215 | $42,311 | $7,975 | $3,175 | $0 | $969 | $788 | $1,114 | $0 | $70 | $536 | $0 | $262 | $0 | $13 | $0 | $0 | $0 | $0 |
| 48 | $000 | Customer | Meters | $16,604 | $12,531 | $1,835 | $444 | $85 | $151 | $128 | $463 | $100 | $41 | $123 | $69 | $21 | $101 | $1 | $42 | $208 | $258 | $3 |
| 49 | $000 | Customer | Meter Reading | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 50 | $000 | Customer | Billing & Collections | $16,127 | $12,891 | $2,067 | $440 | $1 | $157 | $125 | $77 | $2 | $7 | $20 | $1 | $23 | $17 | $1 | $7 | $2 | $96 | $191 |
| 51 | $000 | Customer | Uncollectables | $6,677 | $5,875 | $124 | $26 | $0 | $85 | $68 | $42 | $1 | $23 | $71 | $5 | $119 | $86 | $6 | $36 | $12 | $99 | $0 |
| 52 | $000 | Customer | Customer Service / Other | $6,655 | $5,489 | $745 | $159 | $1 | $52 | $42 | $26 | $1 | $3 | $9 | $1 | $6 | $4 | $0 | $2 | $1 | $38 | $77 |
| 53 | $000 | Customer | Total Customer (Commitment & Billing) | $297,335 | $208,718 | $45,030 | $12,106 | $97 | $6,085 | $5,253 | $4,468 | $112 | $415 | $1,580 | $80 | $546 | $219 | $26 | $86 | $223 | $11,983 | $307 |
| 54 | | | | | | | | | | | | | | | | | | | | | | |
| 55 | | | | | | | | | | | | | | | | | | | | | | |
| 56 | | | Total Revenue @ Full MC ($000) | $1,526,584 | $729,553 | $93,712 | $63,881 | $251 | $41,167 | $59,098 | $82,082 | $1,767 | $13,748 | $84,471 | $5,846 | $36,855 | $23,433 | $37,792 | $95,788 | $120,473 | $35,325 | $1,345 |

5 Year MC

PacifiCorp
Oregon Marginal Cost Study
5 Year Marginal Cost
December 2025 Dollars

| Line | Calculation Component | Class | Units Description / Function | Total | (A) Residential (sec) | (B) General Service - Schedule 23 0-15 kW (sec) | (C) 15+ kW (sec) | (D) Primary (pri) | (E) General Service - Schedule 28 0-50 kW (sec) | (F) 51-100 kW (sec) | (G) 100 + kW (sec) | (H) Primary (pri) | (I) General Service - Schedule 30 0-300 kW (sec) | (J) 300+ kW (sec) | (K) Primary (pri) | (L) Large Power Service - Schedule 48 1 - 4 MW (sec) | (M) 1 - 4 MW (pri) | (N) > 4 MW (sec) | (O) > 4 MW (pri) | (P) Trn (trn) | (Q) Irrg - Sch 41 (sec) | (Q) Streetlighting (sec) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Units | Demand | Peak MW @ Input-System | | 1,107 | 92 | 99 | 0 | 70 | 107 | 153 | 3 | 27 | 166 | 11 | 68 | 75 | 15 | 219 | 231 | 34 | 0 |
| 2 | Units | Energy | Annual MWh @ Input | | 6,248,604 | 599,673 | 652,997 | 1,995 | 459,186 | 708,531 | 1,038,290 | 22,801 | 184,262 | 1,167,972 | 82,702 | 492,415 | 122,047 | 884,743 | 1,436,937 | 2,002,659 | 253,620 | 21,832 |
| 3 | Units | Customer | Average | | 513,581 | 70,880 | 15,103 | 50 | 4,630 | 3,683 | 2,286 | 59 | 200 | 606 | 41 | 82 | 4 | 59 | 25 | 8 | 3,311 | 7,437 |
| 4 | Units | Customer | Annual | | 513,581 | 70,880 | 15,103 | 50 | 4,630 | 3,683 | 2,286 | 59 | 200 | 606 | 41 | 82 | 4 | 59 | 25 | 8 | 7,887 | 7,437 |
| 5 | Units | Customer | Metered Lighting | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 98 |
| 6 | | | | | | | | | | | | | | | | | | | | | | |
| 7 | | | | | | | | | | | | | | | | | | | | | | |
| 8 | $/Unit | Demand | Generation ($/System Peak kW) | | $134.10 | $134.10 | $134.10 | $134.10 | $134.10 | $134.10 | $134.10 | $134.10 | $134.10 | $134.10 | $134.10 | $134.10 | $134.10 | $134.10 | $134.10 | $134.10 | $134.10 | $134.10 |
| 9 | $/Unit | Energy | Generation Energy @ Input ($/kWh) | | $0.05062 | $0.05062 | $0.05062 | $0.05062 | $0.05062 | $0.05062 | $0.05062 | $0.05062 | $0.05062 | $0.05062 | $0.05062 | $0.05062 | $0.05062 | $0.05062 | $0.05062 | $0.05062 | $0.05062 | $0.05062 |
| 10 | $/Unit | Customer | Dist-Service Drop ($/Customer) | | $82.38 | $112.52 | $210.25 | $0.00 | $209.38 | $214.00 | $487.49 | $0.00 | $510.69 | $885.25 | $0.00 | $3,198.62 | $0.00 | $3,198.62 | $0.00 | $0.00 | $0.00 | $0.00 |
| 11 | $/Unit | Customer | Meters ($/Customer) | | $24.40 | $25.89 | $29.39 | $1,693.99 | $32.69 | $34.64 | $202.63 | $1,693.99 | $202.97 | $203.06 | $1,693.99 | $257.45 | $1,693.99 | $257.45 | $1,693.99 | $26,060.93 | $32.77 | $25.89 |
| 12 | $/Unit | Customer | Meter Reading ($/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 | $0.00 |
| 13 | $/Unit | Customer | Billing & Collections ($/Customer) | | $25.10 | $29.16 | $29.16 | $29.16 | $33.83 | $33.83 | $33.83 | $33.83 | $33.83 | $33.83 | $33.83 | $279.41 | $279.41 | $279.41 | $279.41 | $279.41 | $29.14 | $25.72 |
| 14 | $/Unit | Customer | Uncollectables ($/Customer) | | $11.44 | $1.75 | $1.75 | $1.75 | $18.34 | $18.34 | $18.34 | $18.34 | $117.11 | $117.11 | $117.11 | $1,448.51 | $1,448.51 | $1,448.51 | $1,448.51 | $1,448.51 | $29.85 | $0.00 |
| 15 | $/Unit | Customer | Customer Service / Other ($/Customer) | | $10.69 | $10.51 | $10.51 | $10.51 | $11.32 | $11.32 | $11.32 | $11.32 | $15.08 | $15.08 | $15.08 | $75.18 | $75.18 | $75.18 | $75.18 | $75.18 | $11.58 | $10.31 |
| 16 | | | | | | | | | | | | | | | | | | | | | | |
| 17 | | | | | | | | | | | | | | | | | | | | | | |
| 18 | ($000) | Demand | Total Demand | $332,477 | $148,499 | $12,383 | $13,301 | $40 | $9,447 | $14,334 | $20,501 | $439 | $3,641 | $22,317 | $1,534 | $9,111 | $10,083 | $2,060 | $29,303 | $30,924 | $4,540 | $20 |
| 19 | ($000) | Energy | Total Energy | $829,231 | $316,309 | $30,356 | $33,055 | $101 | $23,244 | $35,866 | $52,559 | $1,154 | $9,327 | $59,124 | $4,186 | $24,926 | $6,178 | $44,786 | $72,739 | $101,376 | $12,838 | $1,105 |
| 20 | ($000) | Customer | Total Customer (Billing) | $103,408 | $79,097 | $12,746 | $4,245 | $87 | $1,415 | $1,150 | $1,723 | $104 | $176 | $760 | $76 | $431 | $14 | $312 | $86 | $223 | $492 | $271 |
| 21 | | | Total Revenue @ Full MC ($000) | $1,265,116 | $543,905 | $55,485 | $50,602 | $228 | $34,106 | $51,350 | $74,783 | $1,697 | $13,145 | $82,200 | $5,797 | $34,468 | $16,275 | $47,159 | $102,128 | $132,523 | $17,870 | $1,396 |

1 Year MC

PacifiCorp
Oregon Marginal Cost Study
1 Year Marginal Costs
December 2025 Dollars

| Line | Calculation Component | Class | Units Description / Function | Total | (A) Residential (sec) | (B) General Service - Schedule 23 0-15 kW (sec) | (C) 15+ kW (sec) | (D) Primary (pri) | (E) General Service - Schedule 28 0-50 kW (sec) | (F) 51-100 kW (sec) | (G) 100 + kW (sec) | (H) Primary (pri) | (I) General Service - Schedule 30 0-300 kW (sec) | (J) 300+ kW (sec) | (K) Primary (pri) | (L) Large Power Service - Schedule 48 1 - 4 MW (sec) | (M) 1 - 4 MW (pri) | (N) > 4 MW (sec) | (O) > 4 MW (pri) | (P) Trn (trn) | (Q) Irrg - Sch 41 (sec) | Streetlighting (sec) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Units | Energy | Annual MWh @ Input | | 6,248,604 | 599,673 | 652,997 | 1,995 | 459,186 | 708,531 | 1,038,290 | 22,801 | 184,262 | 1,167,972 | 82,702 | 492,415 | 871,049 | 123,965 | 1,436,937 | 2,002,659 | 253,620 | 21,832 |
| 2 | Units | Customer | Average | | 513,581 | 70,880 | 15,103 | 50 | 4,630 | 3,683 | 2,286 | 59 | 200 | 606 | 41 | 82 | 59 | 4 | 25 | 8 | 3,311 | 7,437 |
| 3 | Units | Customer | Annual | | 513,581 | 70,880 | 15,103 | 50 | 4,630 | 3,683 | 2,286 | 59 | 200 | 606 | 41 | 82 | 59 | 4 | 25 | 8 | 7,887 | 7,437 |
| 4 | Units | Customer | Metered Lighting | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 98 |
| 5 | | | | | | | | | | | | | | | | | | | | | | |
| 6 | | | | | | | | | | | | | | | | | | | | | | |
| 7 | $/Unit | Energy | Generation Energy @ Input ($/kWh) | | $0.08295 | $0.08295 | $0.08295 | $0.08295 | $0.08295 | $0.08295 | $0.08295 | $0.08295 | $0.08295 | $0.08295 | $0.08295 | $0.08295 | $0.08295 | $0.08295 | $0.08295 | $0.08295 | $0.08295 | $0.08295 |
| 8 | $/Unit | Customer | Dist-Service Drop ($/Customer) | | $82.38 | $112.52 | $210.25 | $0.00 | $209.38 | $214.00 | $487.49 | $0.00 | $510.69 | $885.25 | $0.00 | $3,198.62 | $0.00 | $3,198.62 | $0.00 | $0.00 | $0.00 | $0.00 |
| 9 | $/Unit | Customer | Meters ($/Customer) | | $24.40 | $25.89 | $29.39 | $1,693.99 | $32.69 | $34.64 | $138.77 | $1,693.99 | $202.97 | $203.06 | $1,693.99 | $257.45 | $1,693.99 | $257.45 | $1,693.99 | $26,060.93 | $32.77 | $25.89 |
| 10 | $/Unit | Customer | Meter Reading ($/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 | $0.00 |
| 11 | $/Unit | Customer | Billing & Collections ($/Customer) | | $25.10 | $29.16 | $29.16 | $29.16 | $33.83 | $33.83 | $33.83 | $33.83 | $33.83 | $33.83 | $33.83 | $279.41 | $279.41 | $279.41 | $279.41 | $279.41 | $29.14 | $25.72 |
| 12 | $/Unit | Customer | Uncollectables ($/Customer) | | $11.44 | $1.75 | $1.75 | $1.75 | $18.34 | $18.34 | $18.34 | $18.34 | $117.11 | $117.11 | $117.11 | $1,448.51 | $1,448.51 | $1,448.51 | $1,448.51 | $1,448.51 | $29.85 | $0.00 |
| 13 | $/Unit | Customer | Customer Service / Other ($/Customer) | | $10.69 | $10.51 | $10.51 | $10.51 | $11.32 | $11.32 | $11.32 | $11.32 | $15.08 | $15.08 | $15.08 | $75.18 | $75.18 | $75.18 | $75.18 | $75.18 | $11.58 | $10.31 |
| 14 | | | | | | | | | | | | | | | | | | | | | | |
| 15 | | | | | | | | | | | | | | | | | | | | | | |
| 16 | ($000) | Energy | Total Energy | $1,357,904 | $518,343 | $49,745 | $54,168 | $166 | $38,091 | $58,775 | $86,130 | $1,891 | $15,285 | $96,887 | $6,860 | $40,847 | $72,256 | $10,283 | $119,199 | $166,127 | $21,039 | $1,811 |
| 17 | ($000) | Customer | Total Customer (Billing) | $103,164 | $79,097 | $12,746 | $4,245 | $87 | $1,415 | $1,150 | $1,577 | $104 | $176 | $760 | $76 | $431 | $208 | $21 | $86 | $223 | $492 | $271 |
| 18 | | | Total Revenue @ Full MC ($000) | $1,461,068 | $597,440 | $62,491 | $58,413 | $252 | $39,506 | $59,925 | $87,706 | $1,995 | $15,461 | $97,647 | $6,937 | $41,278 | $72,464 | $10,305 | $119,285 | $166,350 | $21,531 | $2,082 |

Generation

PacifiCorp
Oregon Marginal Cost Study
Marginal Generation Costs

| Line | Lithium-Ion, 4-Hour, 1000MW[1] | |
|---|---|---|
| 1 | Total Capital Cost $/kW | $1,816.49 |
| 2 | Payment Factor | 5.557% |
| 3 | Total Capital Cost $/kW-Yr | $100.94 |
| 4 | O&M cost per kW-Yr | 43.12 |
| 5 | Total Cost per kW-Yr | $144.06 |
| 6 | Capacity Contribution[2] | 77% |
| 7 | Capacity Cost $/kW-Yr | $187.77 |

| | | Flat Market Price (MidC Hub)[3] | Energy Benefit of Storage |
|---|---|---|---|
| 8 | 2025 | 94.91 | 83.03 |
| 9 | 2026 | 79.81 | 84.92 |
| 10 | 2027 | 59.47 | 53.33 |
| 11 | 2028 | 54.69 | 24.26 |
| 12 | 2029 | 55.12 | 28.57 |
| 13 | 2030 | 56.40 | 25.92 |
| 14 | 2031 | 56.99 | 26.60 |
| 15 | 2032 | 55.36 | 16.12 |
| 16 | 2033 | 47.28 | 17.65 |
| 17 | 2034 | 48.89 | 18.77 |
| 18 | 2035 | 49.70 | 19.81 |
| 19 | 2036 | 51.27 | 18.93 |
| 20 | 2037 | 54.44 | 18.91 |
| 21 | 2038 | 57.74 | 22.18 |
| 22 | 2039 | 58.76 | 22.06 |
| 23 | 2040 | 62.06 | 27.23 |
| 24 | 2041 | 63.08 | 44.68 |
| 25 | 2042 | 64.76 | 42.84 |
| 26 | 2043 | 66.23 | 43.81 |
| 27 | 2044 | 67.73 | 44.80 |

**Marginal Costs**

| | | Energy Benefit of Storage $/kW-Yr | **Net Capacity Cost $/kW-Yr** | Cost per MWh | Capacity Contribution of Energy | Capacity Credit | **Cost per MWh** |
|---|---|---|---|---|---|---|---|
| 28 | 1 Year | (83.03) | **$104.74** | 94.91 | 100% | -$11.96 | **$82.95** |
| 29 | 5 Years | (53.68) | **$134.10** | 65.93 | 100% | -$15.31 | **$50.62** |
| 30 | 10 Years | (37.99) | **$149.78** | 56.62 | 100% | -$17.10 | **$39.52** |
| 31 | 20 Years | (31.30) | **$156.48** | 50.96 | 100% | -$17.86 | **$33.10** |

[1]2023 Intergrated Resource Plan Volume I

[2]PacifiCorp's 2021 Integrated Resource Plan Volume II, Appendix K

[3]PacifiCorps's March 2023 Official Forward Price Curve in the Avoided Cost Study effective September 2023

Transm

PacifiCorp
Oregon Marginal Cost Study
Marginal Transmission Investment and O&M Expenses
2025 Dollars (000s)

| Line | Description | Forecast Transmission 2024 | 2025 | 2026 | 2027 | 2028 | 2024-2028 |
|---|---|---|---|---|---|---|---|
| 1 | Bulk Power Lines (grid) | $0 | $0 | $0 | $0 | $0 | $0 |
| 2 | Growth Related Major Projects (local) | $9,279 | $32,815 | $83,834 | $93,000 | $40,273 | $259,200 |
| 3 | | | | | | | |
| 4 | Adjusted Bulk Power Lines (grid) | $0 | $0 | $0 | $0 | $0 | $0 |
| 5 | Adjusted Growth Related Major Projects (local) | $9,705 | $34,321 | $87,683 | $97,270 | $42,122 | $271,102 |
| 6 | | | | | | | |
| | Total Growth Related Investments - Demand | $9,705 | $34,321 | $87,683 | $97,270 | $42,122 | $271,101 |
| | Total Growth Related Investments - Energy | $0 | $0 | $0 | $0 | $0 | $0 |
| | Total Marginal Transmission Investment | $9,705 | $34,321 | $87,683 | $97,270 | $42,122 | $271,101 |

| Description | Total | Demand Related | Energy Related |
|---|---|---|---|
| Marginal Investment ($/KW) | $84.43 | $84.43 | $0.00 |
| | | | |
| Annualized Investment ($/KW) | $5.50 | $5.50 | $0.00 |
| Admin. & General Factor ($/KW) | $0.49 | $0.49 | $0.00 |
| Annual O&M Expenses ($/KW) | $0.91 | $0.91 | $0.00 |
| | | | |
| Annualized Marginal Cost ($/KW) | $6.90 | $6.90 | $0.00 |
| | | | |
| Marginal Cost of Energy-Related Transmission ($/KWh) | | | $0.00 |

| Escalation Factor 2023-2025 |
|---|
| 1.0459 |

Footnotes:

Bulk power line & growth related projects data provided in 2023 dollars for each year

Demand Portion of Transmission = PV of Long Run Capacity Costs / PV of Total Long Run Costs = 156.28 / (156.28+39.16) = 82.54%

Energy Portion of Transmission = PV of Long Run Energy Costs / PV of Total Long Run Costs = 39.16 / (156.28+39.16) = 17.46%

Capacity Addition MW from 2024-2028 = 3,211

TransOM

PacifiCorp
Transmission O & M Expenses
(Dollars in 000's)

| Line | Description | Calculation | (A) 2013 | (B) 2014 | (C) 2015 | (D) 2016 | (E) 2017 | (F) 2018 | (G) 2019 | (H) 2020 | (I) 2021 | (J) 2022 | (K) =AVERAGE of (A) thru (J) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Transmission O&M Exp. | | 198,670 | 211,984 | 215,664 | 203,261 | 204,806 | 206,506 | 218,367 | 210,892 | 232,302 | 239,534 | |
| 2 | Wheeling | | 137,182 | 151,336 | 148,425 | 130,789 | 134,473 | 135,022 | 145,825 | 141,188 | 159,058 | 163,235 | |
| 3 | Net Transmission O&M | 1-2 | 61,488 | 60,648 | 67,239 | 72,472 | 70,333 | 71,484 | 72,541 | 69,703 | 73,243 | 76,299 | |
| 4 | Transmission Plant | | 5,231,106 | 5,387,871 | 5,910,756 | 6,051,720 | 6,222,286 | 6,353,045 | 6,478,620 | 7,630,241 | 7,892,551 | 8,048,836 | |
| 5 | Tran. O&M Loading | 3/4 | 1.175% | 1.126% | 1.138% | 1.198% | 1.130% | 1.125% | 1.120% | 0.914% | 0.928% | 0.948% | 1.080% |

Source:
PacifiCorp FERC Form 1
(1) page 321, line 112
(2) page 321, line 96
(4) page 206-07, line 58

TransLF

PacifiCorp
System Load Factor

| Line No. | Month | Total Monthly Energy | Associated Losses | | MW |
|---|---|---|---|---|---|
| | (A) | (B) | (C) | (D) (B)-(C) | (E) |
| 1 | January | 5,930,733 | 495,061 | 5,435,672 | 8,514 |
| 2 | February | 5,316,777 | 456,082 | 4,860,695 | 8,805 |
| 3 | March | 5,393,979 | 539,851 | 4,854,128 | 8,249 |
| 4 | April | 4,994,632 | 424,178 | 4,570,454 | 7,819 |
| 5 | May | 5,002,715 | 304,332 | 4,698,383 | 8,135 |
| 6 | June | 5,470,102 | 583,233 | 4,886,869 | 10,216 |
| 7 | July | 6,444,768 | 259,229 | 6,185,539 | 11,017 |
| 8 | August | 6,252,889 | 267,669 | 5,985,220 | 10,623 |
| 9 | September | 5,311,089 | 312,697 | 4,998,392 | 10,593 |
| 10 | October | 4,979,242 | 311,904 | 4,667,338 | 7,476 |
| 11 | November | 5,382,263 | 258,567 | 5,123,696 | 8,447 |
| 12 | December | 6,008,903 | 350,219 | 5,658,684 | 9,026 |
| 13 | | 66,488,092 | 4,563,022 | 61,925,070 | |
| 14 | | | | | |
| 15 | | | | Average Monthly MW | 9,077 |
| 16 | | | | Load Factor | 77.88% |

Source: FERC Form 1, December 31, 2022
Page 401b

DistSub

PacifiCorp
Oregon Marginal Cost Study
Distribution Substation Costs / kW
2023 Dollars

| Line | Description | Calculation | Value |
|---|---|---|---|
| 1 | Incremental Substation Cost ($/kVA) | | $366.57 |
| 2 | Power Factor | | 0.95 |
| 3 | Installed Capacity (MVA) | | 5172 |
| 4 | Installed Capacity (MW) | | 4914 |
| 5 | Distribution Peak Load | | 2553 |
| 6 | Substation Utilization Factor | | 51.95% |
| 7 | Incremental Substation Cost ($/kW) | 1/2*3 | $200.45 |
| 8 | | | |
| 9 | Annual Distribution Carrying Charge | | 7.21% |
| 10 | | | |
| 11 | Substation Marginal Cost ($/kW) | 4*6 | $14.45 |

Substation Investment

| (A) | (B) | (C) | (D) | (E) | (F) =(E)/(D) |
|---|---|---|---|---|---|
| In Service Year | Substation Capacity Project | State | Capacity Increase (MVA) | Installed Cost (000) | Installed Cost/MVA (000) |
| 2024 | Medford | OR | 25.0 | $3,100 | $124.02 |
| 2025 | Teiton | WA | 25.0 | $5,073 | $202.93 |
| 2025 | Bond | OR | 25.0 | $7,221 | $288.85 |
| 2025 | Rickreall | OR | 30.0 | $9,376 | $312.54 |
| 2026 | Mill City | OR | 25.0 | $9,065 | $362.62 |
| 2026 | Fort Jones | CA | 7.0 | $2,712 | $387.41 |
| 2026 | Banfield | OR | 25.0 | $9,909 | $396.35 |
| 2026 | China Hat | OR | 25.0 | $6,821 | $272.85 |
| 2026 | Ahtanum | WA | 25.0 | $9,285 | $371.41 |
| 2027 | Culver Sub | OR | 12.5 | $5,165 | $413.21 |
| 2027 | Empire and State | OR | 25.0 | $7,699 | $307.97 |
| 2027 | Glendale | OR | 12.5 | $3,596 | $287.65 |
| 2027 | Overpass | OR | 13.0 | $7,879 | $606.07 |
| 2027 | Redmond | OR | 25.0 | $11,226 | $449.05 |
| 2027 | Sulphur Creek | WA | 30.0 | $8,331 | $277.69 |
| 2027 | Wake Robin | OR | 30.0 | $19,686 | $656.20 |
| 2027 | Whetstone | OR | 30.0 | $10,300 | $343.33 |
| 2027 | Lebanon | OR | 10.0 | $6,028 | $602.81 |
| 2028 | Tangent Area | OR | 30.0 | $10,274 | $342.46 |
| 2028 | Walla Walla | WA | 30.0 | $8,470 | $282.34 |
| | | Western States Total | 460.0 | $161,218 | $350.47 |

| Escalation Factor 2023-2025 |
|---|
| 1.0459 |

Incremental Substation Cost ($/KVA) $350.47

PC1

PacifiCorp
Oregon Marginal Cost Study
Calculation of Escalation Factors
Poles and Conductor
Hypothetical Circuit Study Results Annual Demand and Commitment Costs

| Line | Load Class | | Demand | | | | | | Commitment | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Investment $ / kW[1] | | Annual $ / kW[1] | | | | Investment $ / Customer | | Annual $ / Customer | |
| | | | Poles | Conductor | Poles | Conductor | Poles | Conductor | Poles | Conductor | Poles | Conductor | Poles | Conductor |
| 1 | Res - Schedule 4 | (sec) | $ 191.87 | $ 254.38 | $ 200.68 | $ 266.06 | $ 14.47 | $ 19.18 | $ 841.90 | $ 365.91 | $ 880.56 | $ 382.71 | $ 63.49 | $ 27.59 |
| 2 | | | | | | | | | | | | | | |
| 3 | GS - Schedule 23 | | | | | | | | | | | | | |
| 4 | 0-15 kW | (sec) | $ 286.09 | $ 332.38 | $ 299.22 | $ 347.65 | $ 21.57 | $ 25.07 | $ 1,296.15 | $ 563.34 | $ 1,355.66 | $ 589.20 | $ 97.74 | $ 42.48 |
| 5 | 15+ kW | (sec) | $ 286.09 | $ 332.38 | $ 299.22 | $ 347.65 | $ 21.57 | $ 25.07 | $ 1,296.15 | $ 563.34 | $ 1,355.66 | $ 589.20 | $ 97.74 | $ 42.48 |
| 6 | Primary | (pri) | $ 286.09 | $ 332.38 | $ 299.22 | $ 347.65 | $ 21.57 | $ 25.07 | $ 1,296.15 | $ 563.34 | $ 1,355.66 | $ 589.20 | $ 97.74 | $ 42.48 |
| 7 | | | | | | | | | | | | | | |
| 8 | GS - Schedule 28 | | | | | | | | | | | | | |
| 9 | 0-50 kW | (sec) | $ 202.58 | $ 261.28 | $ 211.88 | $ 273.27 | $ 15.28 | $ 19.70 | $ 889.19 | $ 386.46 | $ 930.01 | $ 404.21 | $ 67.05 | $ 29.14 |
| 10 | 51-100 kW | (sec) | $ 202.58 | $ 261.28 | $ 211.88 | $ 273.27 | $ 15.28 | $ 19.70 | $ 889.19 | $ 386.46 | $ 930.01 | $ 404.21 | $ 67.05 | $ 29.14 |
| 11 | 100 + kW | (sec) | $ 202.58 | $ 261.28 | $ 211.88 | $ 273.27 | $ 15.28 | $ 19.70 | $ 889.19 | $ 386.46 | $ 930.01 | $ 404.21 | $ 67.05 | $ 29.14 |
| 12 | Primary | (pri) | $ 202.58 | $ 261.28 | $ 211.88 | $ 273.27 | $ 15.28 | $ 19.70 | $ 889.19 | $ 386.46 | $ 930.01 | $ 404.21 | $ 67.05 | $ 29.14 |
| 13 | | | | | | | | | | | | | | |
| 14 | GS - Schedule 30 | | | | | | | | | | | | | |
| 15 | 0-300 kW | (sec) | $ 141.52 | $ 210.47 | $ 148.02 | $ 220.13 | $ 10.67 | $ 15.87 | $ 594.22 | $ 258.26 | $ 621.50 | $ 270.12 | $ 44.81 | $ 19.48 |
| 16 | 300+ kW | (sec) | $ 137.30 | $ 206.49 | $ 143.60 | $ 215.97 | $ 10.35 | $ 15.57 | $ 572.81 | $ 248.96 | $ 599.11 | $ 260.39 | $ 43.20 | $ 18.77 |
| 17 | Primary | (pri) | $ 141.52 | $ 210.47 | $ 148.02 | $ 220.13 | $ 10.67 | $ 15.87 | $ 594.22 | $ 258.26 | $ 621.50 | $ 270.12 | $ 44.81 | $ 19.48 |
| 18 | | | | | | | | | | | | | | |
| 19 | LPS - Schedule 48 | | | | | | | | | | | | | |
| 20 | 1 - 4 MW | (sec) | $ 274.88 | $ 318.09 | $ 287.50 | $ 332.70 | $ 20.73 | $ 23.99 | $ 1,231.08 | $ 535.06 | $ 1,287.60 | $ 559.62 | $ 92.84 | $ 40.35 |
| 21 | 1 - 4 MW | (pri) | $ 274.88 | $ 318.09 | $ 287.50 | $ 332.70 | $ 20.73 | $ 23.99 | $ 1,231.08 | $ 535.06 | $ 1,287.60 | $ 559.62 | $ 92.84 | $ 40.35 |
| 22 | > 4 MW | (sec) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 23 | > 4 MW | (pri) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 24 | | | | | | | | | | | | | | |
| 25 | Irrigation - Schedule 41 | (sec) | $ 573.90 | $ 586.62 | $ 600.25 | $ 613.55 | $ 43.28 | $ 44.24 | $ 2,718.91 | $ 1,181.70 | $ 2,843.75 | $ 1,235.96 | $ 205.03 | $ 89.11 |

| Escalation Factor 2023-2025 |
|---|
| 1.0459 |

PC 2

PacifiCorp
Oregon Marginal Cost Study
Circuit Distribution Model
Inputs & Calculations

| Line | Class | (A) Annual MWh | (B) Number of Customers | (C) Average MWh per Customer (A) / (B) | (D) Distribution Peak MW | (E) Average kW per customer (D)/(B) * 1,000 | (F) Percent Single Phase |
|---|---|---|---|---|---|---|---|
| 5 | Res - Schedule 4 (sec) | 5,814,272 | 533,013 | 10.91 | 1,213.04 | 2.28 | 100.00% |
| 6 | GS - Schedule 23 - 0-15 kW (sec) | 586,948 | 71,109 | 8.25 | 90.35 | 1.27 | 80.77% |
| 7 | GS - Schedule 23 - 15+ kW (sec) | 639,141 | 15,152 | 42.18 | 97.63 | 6.44 | 54.22% |
| 8 | GS - Schedule 23 - Primary (pri) | 1,955 | 50 | 38.86 | 0.30 | 5.87 | 0.62% |
| 9 | GS - Schedule 28 - 0-50 kW (sec) | 434,116 | 4,543 | 95.57 | 69.55 | 15.31 | 29.27% |
| 10 | GS - Schedule 28 - 51-100 kW (sec) | 669,847 | 3,614 | 185.36 | 104.28 | 28.86 | 14.60% |
| 11 | GS - Schedule 28 - 100 + kW (sec) | 981,603 | 2,243 | 437.7 | 146.51 | 65.33 | 2.48% |
| 12 | GS - Schedule 28 - Primary (pri) | 21,809 | 59 | 372.57 | 3.13 | 53.40 | (0.79%) |
| 13 | GS - Schedule 30 - 0-300 kW (sec) | 170,220 | 198 | 857.81 | 26.14 | 131.75 | 0.42% |
| 14 | GS - Schedule 30 - 300+ kW (sec) | 1,078,967 | 600 | 1797.27 | 157.78 | 262.82 | 0.06% |
| 15 | GS - Schedule 30 - Primary (pri) | 76,532 | 40 | 1893.06 | 11.04 | 273.15 | 1.06% |
| 16 | Irrigation - Sch 41 | 196,326 | 6,149 | 31.93 | 46.96 | 7.64 | 15.70% |
| 17 | LPS - Schedule 48 - 1 - 4 MW (sec) | 456,583 | 81 | 5670.86 | 63.68 | 790.87 | 0.15% |
| 18 | LPS - Schedule 48 - 1 - 4 MW (pri) | 509,238 | 58 | 8766.52 | 71.79 | 1,235.87 | 0.41% |
| 19 | LPS - Schedule 48 - > 4 MW (sec) | 114,945 | 4 | 28616.96 | 14.42 | 3,590.54 | 0.37% |
| 20 | LPS - Schedule 48 - > 4 MW (pri) | 840,070 | 24 | 34873.74 | 207.89 | 8,630.13 | (1.08%) |
| 21 | Total | 12,592,571 | 636,937 | | 2,324.50 | | |

Customer Distribution on the Hypothetical Circuit Branch

| Line | Class | (A) 1 | (B) 2 | (C) 3 | (D) 4 | (E) 5 | (F) 6 | (G) 7 | (H) Branch Total |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Hypothetical Circuit Branch | | | | | |
| 28 | Res - Schedule 4 (sec) | 0.37% | 0.37% | 0.37% | 1.81% | 1.81% | 1.81% | 93.46% | 100.00% |
| 29 | GS - Schedule 23 - 0-15 kW (sec) | 0.69% | 0.69% | 0.69% | 2.57% | 2.57% | 2.57% | 90.19% | 100.00% |
| 30 | GS - Schedule 23 - 15+ kW (sec) | 0.69% | 0.69% | 0.69% | 2.57% | 2.57% | 2.57% | 90.19% | 100.00% |
| 31 | GS - Schedule 23 - Primary (pri) | 0.69% | 0.69% | 0.69% | 2.57% | 2.57% | 2.57% | 90.19% | 100.00% |
| 32 | GS - Schedule 28 - 0-50 kW (sec) | 0.48% | 0.48% | 0.48% | 1.52% | 1.52% | 1.52% | 94.00% | 100.00% |
| 33 | GS - Schedule 28 - 51-100 kW (sec) | 0.48% | 0.48% | 0.48% | 1.52% | 1.52% | 1.52% | 94.00% | 100.00% |
| 34 | GS - Schedule 28 - 100 + kW (sec) | 0.48% | 0.48% | 0.48% | 1.52% | 1.52% | 1.52% | 94.00% | 100.00% |
| 35 | GS - Schedule 28 - Primary (pri) | 0.48% | 0.48% | 0.48% | 1.52% | 1.52% | 1.52% | 94.00% | 100.00% |
| 36 | GS - Schedule 30 - 0-300 kW (sec) | 0.28% | 0.28% | 0.28% | 0.98% | 0.98% | 0.98% | 96.23% | 100.00% |
| 37 | GS - Schedule 30 - 300+ kW (sec) | 0.28% | 0.28% | 0.28% | 0.85% | 0.85% | 0.85% | 96.61% | 100.00% |
| 38 | GS - Schedule 30 - Primary (pri) | 0.28% | 0.28% | 0.28% | 0.98% | 0.98% | 0.98% | 96.23% | 100.00% |
| 39 | Irrigation - Sch 41 | 1.08% | 1.08% | 1.08% | 7.97% | 7.97% | 7.97% | 72.85% | 100.00% |
| 40 | LPS - Schedule 48 - 1 - 4 MW (sec) | 0.85% | 0.85% | 0.85% | 1.52% | 1.52% | 1.52% | 92.89% | 100.00% |
| 41 | LPS - Schedule 48 - 1 - 4 MW (pri) | 0.85% | 0.85% | 0.85% | 1.52% | 1.52% | 1.52% | 92.89% | 100.00% |
| 42 | LPS - Schedule 48 - > 4 MW (sec) | | Large Customers are on dedicated circuits and are not included here | | | | | | |
| 43 | LPS - Schedule 48 - > 4 MW (pri) | | Large Customers are on dedicated circuits and are not included here | | | | | | |

| | | |
|---|---|---|
| | System property records & engineering information | |
| Number of pole feet in Oregon | | 75,736,758 |
| Number of pole miles in Oregon | | 14,344 |
| Number of trench feet in Oregon | | 29,644,711 |
| Number of trench miles in Oregon | | 5,615 |
| Total miles in Oregon | | 19,959 |
| Number of circuits in Oregon | | 530 |
| Number of poles in Oregon | | 380,944 |
| Poles per mile | | 26.56 |
| Customers per mile | | 31.91 |
| MWh per customer | | 19.77 |
| MWh per circuit | | 23,760 |
| Branches per circuit | | 7 |
| Miles per circuit | | 37.66 |
| Miles per branch | | 5.38 |
| Single Phase Miles per Branch[1] | | 1.88 |
| Average Trunk Length | | 0.67 |

[1]A 12 KV circuit 12 miles long has approx. 3 miles of single phase, which is approx. 25 percent of circuit distance, so applying 25% to the Miles per Circuit and dividing this amount by the 5 outer branches gives the Single Phase Miles per Branch.

PC 3

PacifiCorp
Oregon Circuit Model Study
Average Customers by Hypothetical Circuit Branch

| Line | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | Hypothetical Circuit Branch | | | | | | | |
| 2 | Class | 1 | 2 | 3 | 4 | 5 | 6 | 7 | Total |
| 3 | Res - Schedule 4 (sec) | 3.71 | 3.71 | 3.71 | 18.21 | 18.21 | 18.21 | 939.93 | 1,005.68 |
| 4 | GS - Schedule 23 - 0-15 kW (sec) | 0.93 | 0.93 | 0.93 | 3.45 | 3.45 | 3.45 | 121.01 | 134.17 |
| 5 | GS - Schedule 23 - 15+ kW (sec) | 0.20 | 0.20 | 0.20 | 0.74 | 0.74 | 0.74 | 25.79 | 28.59 |
| 6 | GS - Schedule 23 - Primary (pri) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 0.09 |
| 7 | GS - Schedule 28 - 0-50 kW (sec) | 0.04 | 0.04 | 0.04 | 0.13 | 0.13 | 0.13 | 8.06 | 8.57 |
| 8 | GS - Schedule 28 - 51-100 kW (sec) | 0.03 | 0.03 | 0.03 | 0.10 | 0.10 | 0.10 | 6.41 | 6.82 |
| 9 | GS - Schedule 28 - 100 + kW (sec) | 0.02 | 0.02 | 0.02 | 0.06 | 0.06 | 0.06 | 3.98 | 4.23 |
| 10 | GS - Schedule 28 - Primary (pri) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.11 |
| 11 | GS - Schedule 30 - 0-300 kW (sec) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.36 | 0.37 |
| 12 | GS - Schedule 30 - 300+ kW (sec) | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.01 | 1.09 | 1.13 |
| 13 | GS - Schedule 30 - Primary (pri) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.07 | 0.08 |
| 14 | Irrigation - Sch 41 | 0.13 | 0.13 | 0.13 | 0.92 | 0.92 | 0.92 | 8.45 | 11.60 |
| 15 | LPS - Schedule 48 - 1 - 4 MW (sec) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.14 | 0.15 |
| 16 | LPS - Schedule 48 - 1 - 4 MW (pri) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.11 |
| 17 | LPS - Schedule 48 - > 4 MW (sec) | - | - | - | - | - | - | - | - |
| 18 | LPS - Schedule 48 - > 4 MW (pri) | - | - | - | - | - | - | - | - |
| 19 | Total | 5.06 | 5.06 | 5.06 | 23.65 | 23.65 | 23.65 | 1,115.58 | 1,201.72 |
| 20 | | | | | | | | | |
| 21 | Source - 'Circuit Distribution Model Inputs & Calculations' (PC 2) | | | | | | | | |
| 22 | Source - 'Customer Distribution on the Hypothetical Circuit Branch' (PC 2) | | | | | | | | |
| 23 | Customers multiplied by Customer Distribution on the Hypothetical Circuit Branch divided by circuits in the state. | | | | | | | | |
| 24 | For Example 3.71 is 533,013 Residential Customers X .368% customers on Branch 1 divided by 530 circuits. | | | | | | | | |
| 25 | | | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 26 | Percent of Customers | | | | | | | | |
| 27 | Res - Schedule 4 (sec) | 73.18% | 73.18% | 73.18% | 77.02% | 77.02% | 77.02% | 84.25% | 83.69% |
| 28 | GS - Schedule 23 - 0-15 kW (sec) | 18.40% | 18.40% | 18.40% | 14.61% | 14.61% | 14.61% | 10.85% | 11.16% |
| 29 | GS - Schedule 23 - 15+ kW (sec) | 3.92% | 3.92% | 3.92% | 3.11% | 3.11% | 3.11% | 2.31% | 2.38% |
| 30 | GS - Schedule 23 - Primary (pri) | 0.01% | 0.01% | 0.01% | 0.01% | 0.01% | 0.01% | 0.01% | 0.01% |
| 31 | GS - Schedule 28 - 0-50 kW (sec) | 0.81% | 0.81% | 0.81% | 0.55% | 0.55% | 0.55% | 0.72% | 0.71% |
| 32 | GS - Schedule 28 - 51-100 kW (sec) | 0.65% | 0.65% | 0.65% | 0.44% | 0.44% | 0.44% | 0.57% | 0.57% |
| 33 | GS - Schedule 28 - 100 + kW (sec) | 0.40% | 0.40% | 0.40% | 0.27% | 0.27% | 0.27% | 0.36% | 0.35% |
| 34 | GS - Schedule 28 - Primary (pri) | 0.01% | 0.01% | 0.01% | 0.01% | 0.01% | 0.01% | 0.01% | 0.01% |
| 35 | GS - Schedule 30 - 0-300 kW (sec) | 0.02% | 0.02% | 0.02% | 0.02% | 0.02% | 0.02% | 0.03% | 0.03% |
| 36 | GS - Schedule 30 - 300+ kW (sec) | 0.06% | 0.06% | 0.06% | 0.04% | 0.04% | 0.04% | 0.10% | 0.09% |
| 37 | GS - Schedule 30 - Primary (pri) | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.01% | 0.01% |
| 38 | Irrigation - Sch 41 | 2.48% | 2.48% | 2.48% | 3.91% | 3.91% | 3.91% | 0.76% | 0.97% |
| 39 | LPS - Schedule 48 - 1 - 4 MW (sec) | 0.03% | 0.03% | 0.03% | 0.01% | 0.01% | 0.01% | 0.01% | 0.01% |
| 40 | LPS - Schedule 48 - 1 - 4 MW (pri) | 0.02% | 0.02% | 0.02% | 0.01% | 0.01% | 0.01% | 0.01% | 0.01% |
| 41 | LPS - Schedule 48 - > 4 MW (sec) | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 42 | LPS - Schedule 48 - > 4 MW (pri) | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 43 | Total | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% |
| 44 | | | | | | | | | |
| 45 | Sum of Branch Customers | | | | | | | | |
| 46 | 1,2,3,6 | 5.06 | 5.06 | 5.06 | | | 23.65 | | 38.84 |
| 47 | 1,2,3,4,5,6,7 | 5.06 | 5.06 | 5.06 | 23.65 | 23.65 | 23.65 | 1,115.58 | 1,201.72 |
| 48 | | | | | | | | | |
| 49 | 1,2,3,6 | 13.0% | 13.0% | 13.0% | 0.0% | 0.0% | 60.9% | 0.0% | 100.0% |
| 50 | 1,2,3,4,5,6,7 | 0.4% | 0.4% | 0.4% | 2.0% | 2.0% | 2.0% | 92.8% | 100.0% |

PacifiCorp
Oregon Circuit Model Study
Circuit kW Load by Branch

| Line | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | Hypothetical Circuit Branch | | | | | | | |
| 2 | Class | 1 | 2 | 3 | 4 | 5 | 6 | 7 | Total |
| 3 | Res - Schedule 4 (sec) | 8.43 | 8.43 | 8.43 | 41.45 | 41.45 | 41.45 | 2,139.10 | 2,288.76 |
| 4 | GS - Schedule 23 - 0-15 kW (sec) | 1.18 | 1.18 | 1.18 | 4.39 | 4.39 | 4.39 | 153.76 | 170.48 |
| 5 | GS - Schedule 23 - 15+ kW (sec) | 1.28 | 1.28 | 1.28 | 4.74 | 4.74 | 4.74 | 166.14 | 184.21 |
| 6 | GS - Schedule 23 - Primary (pri) | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.01 | 0.50 | 0.56 |
| 7 | GS - Schedule 28 - 0-50 kW (sec) | 0.63 | 0.63 | 0.63 | 1.99 | 1.99 | 1.99 | 123.35 | 131.23 |
| 8 | GS - Schedule 28 - 51-100 kW (sec) | 0.95 | 0.95 | 0.95 | 2.99 | 2.99 | 2.99 | 184.95 | 196.76 |
| 9 | GS - Schedule 28 - 100 + kW (sec) | 1.33 | 1.33 | 1.33 | 4.20 | 4.20 | 4.20 | 259.85 | 276.44 |
| 10 | GS - Schedule 28 - Primary (pri) | 0.03 | 0.03 | 0.03 | 0.09 | 0.09 | 0.09 | 5.54 | 5.90 |
| 11 | GS - Schedule 30 - 0-300 kW (sec) | 0.14 | 0.14 | 0.14 | 0.48 | 0.48 | 0.48 | 47.47 | 49.33 |
| 12 | GS - Schedule 30 - 300+ kW (sec) | 0.84 | 0.84 | 0.84 | 2.53 | 2.53 | 2.53 | 287.59 | 297.70 |
| 13 | GS - Schedule 30 - Primary (pri) | 0.06 | 0.06 | 0.06 | 0.20 | 0.20 | 0.20 | 20.05 | 20.84 |
| 14 | Irrigation - Sch 41 | 0.96 | 0.96 | 0.96 | 7.06 | 7.06 | 7.06 | 64.56 | 88.61 |
| 15 | LPS - Schedule 48 - 1 - 4 MW (sec) | 1.02 | 1.02 | 1.02 | 1.83 | 1.83 | 1.83 | 111.61 | 120.14 |
| 16 | LPS - Schedule 48 - 1 - 4 MW (pri) | 1.15 | 1.15 | 1.15 | 2.06 | 2.06 | 2.06 | 125.83 | 135.45 |
| 17 | LPS - Schedule 48 - > 4 MW (sec) | - | - | - | - | - | - | - | - |
| 18 | LPS - Schedule 48 - > 4 MW (pri) | - | - | - | - | - | - | - | - |
| 19 | Total | 17.99 | 17.99 | 17.99 | 74.03 | 74.03 | 74.03 | 3,690.31 | 3,966.39 |
| 20 | | | | | | | | | |
| 21 | Source - 'Circuit Distribution Model Inputs & Calculations' (PC 2) | | | | | | | | |
| 22 | Source - 'Average Customers by Hypothetical Circuit Branch' (PC 3) | | | | | | | | |
| 23 | Customers multiplied by circuit kW per customer. | | | | | | | | |
| 24 | For Example 8.4 is 3.71 Residential Customers multiplied by 2.28 average Dist. kW per Customer. | | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 25 | | | | | | | | | |
| 26 | Percent of Branch Load | | | | | | | | |
| 27 | Res - Schedule 4 (sec) | 46.87% | 46.87% | 46.87% | 55.99% | 55.99% | 55.99% | 57.97% | 57.70% |
| 28 | GS - Schedule 23 - 0-15 kW (sec) | 6.58% | 6.58% | 6.58% | 5.93% | 5.93% | 5.93% | 4.17% | 4.30% |
| 29 | GS - Schedule 23 - 15+ kW (sec) | 7.11% | 7.11% | 7.11% | 6.41% | 6.41% | 6.41% | 4.50% | 4.64% |
| 30 | GS - Schedule 23 - Primary (pri) | 0.02% | 0.02% | 0.02% | 0.02% | 0.02% | 0.02% | 0.01% | 0.01% |
| 31 | GS - Schedule 28 - 0-50 kW (sec) | 3.50% | 3.50% | 3.50% | 2.69% | 2.69% | 2.69% | 3.34% | 3.31% |
| 32 | GS - Schedule 28 - 51-100 kW (sec) | 5.25% | 5.25% | 5.25% | 4.04% | 4.04% | 4.04% | 5.01% | 4.96% |
| 33 | GS - Schedule 28 - 100 + kW (sec) | 7.38% | 7.38% | 7.38% | 5.68% | 5.68% | 5.68% | 7.04% | 6.97% |
| 34 | GS - Schedule 28 - Primary (pri) | 0.16% | 0.16% | 0.16% | 0.12% | 0.12% | 0.12% | 0.15% | 0.15% |
| 35 | GS - Schedule 30 - 0-300 kW (sec) | 0.76% | 0.76% | 0.76% | 0.65% | 0.65% | 0.65% | 1.29% | 1.24% |
| 36 | GS - Schedule 30 - 300+ kW (sec) | 4.68% | 4.68% | 4.68% | 3.41% | 3.41% | 3.41% | 7.79% | 7.51% |
| 37 | GS - Schedule 30 - Primary (pri) | 0.32% | 0.32% | 0.32% | 0.27% | 0.27% | 0.27% | 0.54% | 0.53% |
| 38 | Irrigation - Sch 41 | 5.33% | 5.33% | 5.33% | 9.53% | 9.53% | 9.53% | 1.75% | 2.23% |
| 39 | LPS - Schedule 48 - 1 - 4 MW (sec) | 5.65% | 5.65% | 5.65% | 2.47% | 2.47% | 2.47% | 3.02% | 3.03% |
| 40 | LPS - Schedule 48 - 1 - 4 MW (pri) | 6.37% | 6.37% | 6.37% | 2.79% | 2.79% | 2.79% | 3.41% | 3.42% |
| 41 | LPS - Schedule 48 - > 4 MW (sec) | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 42 | LPS - Schedule 48 - > 4 MW (pri) | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 43 | Total | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% |
| 44 | | | | | | | | | |
| 45 | Sum of Branch Loads | | | | | | | | |
| 46 | 1,2,3,6 | 17.99 | 17.99 | 17.99 | | | 74.03 | | 128.01 |
| 47 | 1,2,3,4,5,6,7 | 17.99 | 17.99 | 17.99 | 74.03 | 74.03 | 74.03 | 3,690.31 | 3,966.39 |
| 48 | | | | | | | | | |
| 49 | 1,2,3,6 | 14.06% | 14.06% | 14.06% | | | 57.83% | | 100.00% |
| 50 | 1,2,3,4,5,6,7 | 0.45% | 0.45% | 0.45% | 1.87% | 1.87% | 1.87% | 93.04% | 100.00% |

PC 4

PacifiCorp
Oregon Circuit Model Study
System-wide Pole and Conductor Costs

Adjusted Oregon Line Costs per Mile

| | State Specific Account 364 Pole Statistics | | | | Adjustment |
|---|---|---|---|---|---|
| | Poles | Pole Feet | Pole Miles | Poles / Mile | Factor |
| California | 55,683 | 12,642,710 | 2,394 | 23.26 | 0.865 |
| Idaho | 97,904 | 21,437,890 | 4,060 | 24.11 | 0.897 |
| Oregon | 380,944 | 75,736,758 | 14,344 | 26.56 | 0.988 |
| Utah | 351,303 | 60,938,569 | 11,541 | 30.44 | 1.132 |
| Washington | 100,586 | 16,791,482 | 3,180 | 31.63 | 1.176 |
| Wyoming | 159,614 | 37,458,548 | 7,094 | 22.50 | 0.837 |
| Total | 1,146,034 | 225,005,957 | 42,615 | 26.89 | 1.000 |

| | | Account 364 Pole Cost per Mile | | | Account 365 | Total Line |
|---|---|---|---|---|---|---|
| | Wire Size | Pole Cost per Mile | Adjustment Factor | Adjusted Pole Cost | Conductor Cost per Mile | Construction Cost |
| 1 | 1 Phase - 1/0 ACSR | $29,797 | 0.988 | $29,425 | $12,789 | $42,214 |
| 2 | 3 Phase - 1/0 ACSR | $56,836 | 0.988 | $56,127 | $28,548 | $84,675 |
| 3 | 447 AAC & 4\0 AAC | $63,338 | 0.988 | $62,548 | $62,952 | $125,500 |
| 4 | 795 AAC & 477 AAC | $65,804 | 0.988 | $64,984 | $110,173 | $175,157 |

| | Costs for Branches 1,2,3,4,5 | | |
|---|---|---|---|
| | 1 Phase - 1/0 ACSR | 3 Phase - 1/0 ACSR | Total |
| Poles | $55,405 | $196,266 | $251,670 |
| Conductors | $24,080 | $99,826 | $123,907 |
| Total | $79,485 | $296,092 | $375,577 |

| | Costs for Branch 6 | Cost for Branch 7 |
|---|---|---|
| | 3 Phase - 447 AAC & 4\0 AAC | 3 Phase -795 AAC & 477 AAC |
| Poles | $336,490 | $349,591 |
| Conductors | $338,662 | $592,695 |
| Total | $675,151 | $942,286 |

| | |
|---|---|
| Miles per Branch | 5.38 |
| Single Phase Miles Per Branch | 1.88 |
| Three Phase Miles Per Branch | 3.50 |

Commitment and Demand Costs Per Branch

| | Poles | | | Conductor | | | |
|---|---|---|---|---|---|---|---|
| | Total Cost | Commitment | Demand | Total Cost | Commitment | Demand | Total |
| Branches 1,2,3,4,5 | | | | | | | |
| 1 Phase - 1/0 ACSR | $55,405 | $55,405 | $0 | $24,080 | $24,080 | $0 | $79,485 |
| 3 Phase - 1/0 ACSR | $196,266 | $102,895 | $93,371 | $99,826 | $44,720 | $55,106 | $296,092 |
| Total Branches 1,2,3,4,5 | $251,670 | $158,300 | $93,371 | $123,907 | $68,801 | $55,106 | $375,577 |
| Branch 6 | | | | | | | $0 |
| 3 Phase - 447 AAC & 4\0 AAC | $336,490 | $158,300 | $178,190 | $338,662 | $68,801 | $269,861 | $675,151 |
| Branch 7 | | | | | | | $0 |
| 3 Phase -795 AAC & 477 AAC | $349,591 | $158,300 | $191,291 | $592,695 | $68,801 | $523,895 | $942,286 |
| Total All Branches | $1,944,433 | $1,108,097 | $836,335 | $1,550,890 | $481,605 | $1,069,285 | $3,495,323 |

Branch pole and conductor commitment costs equals single or three Phase Miles Per Branch Multiplied by 1 Phase - 1/0 ACSR Cost

PC 5

PacifiCorp
Oregon Circuit Model Study
Demand Calculations

| Line | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Poles | | | | | | | | |
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | Total | |
| 1 | % customer | 14.06% | 14.06% | 14.06% | | | 57.83% | | 100.00% | |
| 2 | Branch 6 Cost | $ 25,045 | $ 25,045 | $ 25,045 | | | $ 103,055 | | $ 178,190 | $ / kW |
| 3 | % customer | 0.45% | 0.45% | 0.45% | 1.87% | 1.87% | 1.87% | 93.04% | 100.00% | |
| 4 | Branch 7 Cost | $ 868 | $ 868 | $ 868 | $ 3,571 | $ 3,571 | $ 3,571 | $ 177,976 | $ 191,291 | |
| 5 | Branch Commitment Cost | $ 93,371 | $ 93,371 | $ 93,371 | $ 93,371 | $ 93,371 | | | | Average |
| 6 | Total | $ 119,284 | $ 119,284 | $ 119,284 | $ 96,941 | $ 96,941 | $ 106,625 | $ 177,976 | $ 836,335 | $ 210.86 |
| 7 | | | | | | | | | | |
| 8 | | | | | | | | | Total | |
| 9 | | | | | | | | | Demand | $ Per |
| 10 | Class Cost per Branch | 1 | 2 | 3 | 4 | 5 | 6 | 7 | Cost | kW |
| 11 | Res - Schedule 4 (sec) | $ 55,912 | $ 55,912 | $ 55,912 | $ 54,276 | $ 54,276 | $ 59,698 | $ 103,165 | $ 439,152 | $ 191.87 |
| 12 | GS - Schedule 23 - 0-15 kW (sec) | $ 7,847 | $ 7,847 | $ 7,847 | $ 5,747 | $ 5,747 | $ 6,321 | $ 7,416 | $ 48,771 | $ 286.09 |
| 13 | GS - Schedule 23 - 15+ kW (sec) | $ 8,479 | $ 8,479 | $ 8,479 | $ 6,210 | $ 6,210 | $ 6,830 | $ 8,013 | $ 52,700 | $ 286.09 |
| 14 | GS - Schedule 23 - Primary (pri) | $ 26 | $ 26 | $ 26 | $ 19 | $ 19 | $ 21 | $ 24 | $ 159 | $ 286.09 |
| 15 | GS - Schedule 28 - 0-50 kW (sec) | $ 4,180 | $ 4,180 | $ 4,180 | $ 2,612 | $ 2,612 | $ 2,873 | $ 5,949 | $ 26,584 | $ 202.58 |
| 16 | GS - Schedule 28 - 51-100 kW (sec) | $ 6,267 | $ 6,267 | $ 6,267 | $ 3,916 | $ 3,916 | $ 4,307 | $ 8,920 | $ 39,859 | $ 202.58 |
| 17 | GS - Schedule 28 - 100 + kW (sec) | $ 8,805 | $ 8,805 | $ 8,805 | $ 5,502 | $ 5,502 | $ 6,051 | $ 12,532 | $ 56,002 | $ 202.58 |
| 18 | GS - Schedule 28 - Primary (pri) | $ 188 | $ 188 | $ 188 | $ 117 | $ 117 | $ 129 | $ 267 | $ 1,195 | $ 202.58 |
| 19 | GS - Schedule 30 - 0-300 kW (sec) | $ 912 | $ 912 | $ 912 | $ 631 | $ 631 | $ 694 | $ 2,289 | $ 6,981 | $ 141.52 |
| 20 | GS - Schedule 30 - 300+ kW (sec) | $ 5,583 | $ 5,583 | $ 5,583 | $ 3,308 | $ 3,308 | $ 3,639 | $ 13,870 | $ 40,874 | $ 137.30 |
| 21 | GS - Schedule 30 - Primary (pri) | $ 385 | $ 385 | $ 385 | $ 266 | $ 266 | $ 293 | $ 967 | $ 2,949 | $ 141.52 |
| 22 | Irrigation - Sch 41 | $ 6,363 | $ 6,363 | $ 6,363 | $ 9,242 | $ 9,242 | $ 10,165 | $ 3,113 | $ 50,853 | $ 573.90 |
| 23 | LPS - Schedule 48 - 1 - 4 MW (sec) | $ 6,739 | $ 6,739 | $ 6,739 | $ 2,396 | $ 2,396 | $ 2,635 | $ 5,383 | $ 33,025 | $ 274.88 |
| 24 | LPS - Schedule 48 - 1 - 4 MW (pri) | $ 7,597 | $ 7,597 | $ 7,597 | $ 2,701 | $ 2,701 | $ 2,971 | $ 6,068 | $ 37,233 | $ 274.88 |
| 25 | LPS - Schedule 48 - > 4 MW (sec) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 26 | LPS - Schedule 48 - > 4 MW (pri) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 27 | Check Total | $ 119,284 | $ 119,284 | $ 119,284 | $ 96,941 | $ 96,941 | $ 106,625 | $ 177,976 | $ 836,335 | |

Sources: Line 1 & 3 - 'Circuit kW Load by Branch' (PC 3)
Line 2 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 4) for178,190
Line 1 X 178,190
Line 4 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 4) for191,291
Line 3 X 191,291
Line 5 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 4)
Line 7 to 18 - Line 6 X Percent of Branch Load 'Circuit kW Load by Branch' (PC 3)

PacifiCorp
Oregon Circuit Model Study
Demand Calculations

| (J) | (K) | (L) | (M) | (N) | (O) | (P) | (Q) | (R) |
|---|---|---|---|---|---|---|---|---|
| Conductors | | | | | | | | |
| 1 | 2 | 3 | 4 | 5 | 6 | 7 | Total | |
| 14.06% | 14.06% | 14.06% | | | 57.83% | | 100.00% | |
| $ 37,929.76 | $ 37,929.76 | $ 37,929.76 | $ - | $ - | $ 156,071.59 | $ - | $ 269,861 | $ / kW |
| 0.45% | 0.45% | 0.45% | 1.87% | 1.87% | 1.87% | 93.04% | 100.00% | |
| $ 2,377 | $ 2,377 | $ 2,377 | $ 9,779 | $ 9,779 | $ 9,779 | $ 487,429 | $ 523,895 | |
| $ 55,106 | $ 55,106 | $ 55,106 | $ 55,106 | $ 55,106 | | | | Average |
| $ 95,412 | $ 95,412 | $ 95,412 | $ 64,885 | $ 64,885 | $ 165,850 | $ 487,429 | $ 1,069,285 | $ 269.59 |
| | | | | | | | | |
| 1 | 2 | 3 | 4 | 5 | 6 | 7 | Total Demand Cost | $ Per kW |
| $ 44,723 | $ 44,723 | $ 44,723 | $ 36,328 | $ 36,328 | $ 92,857 | $ 282,540 | $ 582,222 | $ 254.38 |
| $ 6,277 | $ 6,277 | $ 6,277 | $ 3,846 | $ 3,846 | $ 9,832 | $ 20,309 | $ 56,664 | $ 332.38 |
| $ 6,782 | $ 6,782 | $ 6,782 | $ 4,156 | $ 4,156 | $ 10,623 | $ 21,945 | $ 61,228 | $ 332.38 |
| $ 20 | $ 20 | $ 20 | $ 13 | $ 13 | $ 32 | $ 66 | $ 185 | $ 332.38 |
| $ 3,343 | $ 3,343 | $ 3,343 | $ 1,748 | $ 1,748 | $ 4,468 | $ 16,293 | $ 34,287 | $ 261.28 |
| $ 5,013 | $ 5,013 | $ 5,013 | $ 2,621 | $ 2,621 | $ 6,699 | $ 24,429 | $ 51,408 | $ 261.28 |
| $ 7,043 | $ 7,043 | $ 7,043 | $ 3,682 | $ 3,682 | $ 9,413 | $ 34,322 | $ 72,228 | $ 261.28 |
| $ 150 | $ 150 | $ 150 | $ 79 | $ 79 | $ 201 | $ 732 | $ 1,541 | $ 261.28 |
| $ 730 | $ 730 | $ 730 | $ 422 | $ 422 | $ 1,079 | $ 6,270 | $ 10,382 | $ 210.47 |
| $ 4,466 | $ 4,466 | $ 4,466 | $ 2,214 | $ 2,214 | $ 5,660 | $ 37,986 | $ 61,471 | $ 206.49 |
| $ 308 | $ 308 | $ 308 | $ 178 | $ 178 | $ 456 | $ 2,648 | $ 4,385 | $ 210.47 |
| $ 5,090 | $ 5,090 | $ 5,090 | $ 6,186 | $ 6,186 | $ 15,812 | $ 8,527 | $ 51,980 | $ 586.62 |
| $ 5,390 | $ 5,390 | $ 5,390 | $ 1,603 | $ 1,603 | $ 4,099 | $ 14,741 | $ 38,217 | $ 318.09 |
| $ 6,077 | $ 6,077 | $ 6,077 | $ 1,808 | $ 1,808 | $ 4,621 | $ 16,620 | $ 43,087 | $ 318.09 |
| $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| $ 95,412 | $ 95,412 | $ 95,412 | $ 64,885 | $ 64,885 | $ 165,850 | $ 487,429 | $ 1,069,285 | |

PC 6

PacifiCorp
Oregon Circuit Model Study
Commitment Calculations

| Line | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Poles | | | | | | | | |
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | Total | |
| 1 | % customer | 13.04% | 13.04% | 13.04% | | | 60.89% | | 100.00% | |
| 2 | Branch 6 Cost | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ Per |
| 3 | % customer | 0.42% | 0.42% | 0.42% | 1.97% | 1.97% | 1.97% | 92.83% | 100.00% | Customer |
| 4 | Branch 7 Cost | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| 5 | Branch Commitment Cost | $ 158,300 | $ 158,300 | $ 158,300 | $ 158,300 | $ 158,300 | $ 158,300 | $ 158,300 | | Average |
| 6 | Total | $ 158,300 | $ 158,300 | $ 158,300 | $ 158,300 | $ 158,300 | $ 158,300 | $ 158,300 | $ 1,108,097 | $ 922.10 |
| 7 | | | | | | | | | | |
| 8 | | | | | | | | | Total | |
| 9 | | | | | | | | | Demand | $ Per |
| 10 | Class Cost per Branch | 1 | 2 | 3 | 4 | 5 | 6 | 7 | Cost | Customer |
| 11 | Res - Schedule 4 (sec) | $ 115,850 | $ 115,850 | $ 115,850 | $ 121,921 | $ 121,921 | $ 121,921 | $ 133,375 | $ 846,687 | $ 841.90 |
| 12 | GS - Schedule 23 - 0-15 kW (sec) | $ 29,122 | $ 29,122 | $ 29,122 | $ 23,121 | $ 23,121 | $ 23,121 | $ 17,171 | $ 173,902 | $ 1,296.15 |
| 13 | GS - Schedule 23 - 15+ kW (sec) | $ 6,205 | $ 6,205 | $ 6,205 | $ 4,927 | $ 4,927 | $ 4,927 | $ 3,659 | $ 37,055 | $ 1,296.15 |
| 14 | GS - Schedule 23 - Primary (pri) | $ 21 | $ 21 | $ 21 | $ 16 | $ 16 | $ 16 | $ 12 | $ 123 | $ 1,296.15 |
| 15 | GS - Schedule 28 - 0-50 kW (sec) | $ 1,287 | $ 1,287 | $ 1,287 | $ 872 | $ 872 | $ 872 | $ 1,143 | $ 7,621 | $ 889.19 |
| 16 | GS - Schedule 28 - 51-100 kW (sec) | $ 1,024 | $ 1,024 | $ 1,024 | $ 694 | $ 694 | $ 694 | $ 909 | $ 6,063 | $ 889.19 |
| 17 | GS - Schedule 28 - 100 + kW (sec) | $ 636 | $ 636 | $ 636 | $ 431 | $ 431 | $ 431 | $ 564 | $ 3,763 | $ 889.19 |
| 18 | GS - Schedule 28 - Primary (pri) | $ 17 | $ 17 | $ 17 | $ 11 | $ 11 | $ 11 | $ 15 | $ 98 | $ 889.19 |
| 19 | GS - Schedule 30 - 0-300 kW (sec) | $ 33 | $ 33 | $ 33 | $ 24 | $ 24 | $ 24 | $ 51 | $ 222 | $ 594.22 |
| 20 | GS - Schedule 30 - 300+ kW (sec) | $ 100 | $ 100 | $ 100 | $ 64 | $ 64 | $ 64 | $ 155 | $ 649 | $ 572.81 |
| 21 | GS - Schedule 30 - Primary (pri) | $ 7 | $ 7 | $ 7 | $ 5 | $ 5 | $ 5 | $ 10 | $ 45 | $ 594.22 |
| 22 | Irrigation - Sch 41 | $ 3,929 | $ 3,929 | $ 3,929 | $ 6,187 | $ 6,187 | $ 6,187 | $ 1,199 | $ 31,546 | $ 2,718.91 |
| 23 | LPS - Schedule 48 - 1 - 4 MW (sec) | $ 40 | $ 40 | $ 40 | $ 15 | $ 15 | $ 15 | $ 20 | $ 187 | $ 1,231.08 |
| 24 | LPS - Schedule 48 - 1 - 4 MW (pri) | $ 29 | $ 29 | $ 29 | $ 11 | $ 11 | $ 11 | $ 14 | $ 135 | $ 1,231.08 |
| 25 | LPS - Schedule 48 - > 4 MW (sec) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 26 | LPS - Schedule 48 - > 4 MW (pri) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 27 | Check Total | $ 158,300 | $ 158,300 | $ 158,300 | $ 158,300 | $ 158,300 | $ 158,300 | $ 158,300 | $ 1,108,097 | |

PacifiCorp
Oregon Circuit Model Study
Commitment Calculations

| (J) | (K) | (L) | (M) | (N) | (O) | (P) | (Q) | (R) |
|---|---|---|---|---|---|---|---|---|
| Conductors | | | | | | | | |
| 1 | 2 | 3 | 4 | 5 | 6 | 7 | Total | |
| 13.04% | 13.04% | 13.04% | 0.00% | 0.00% | 60.89% | 0.00% | 100.00% | |
| $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ Per |
| 0.42% | 0.42% | 0.42% | 1.97% | 1.97% | 1.97% | 92.83% | 100.00% | Customer |
| $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| $68,801 | $68,801 | $68,801 | $68,801 | $68,801 | $68,801 | $68,801 | | Average |
| $68,801 | $68,801 | $68,801 | $68,801 | $68,801 | $68,801 | $68,801 | $481,605 | $ 400.76 |
| | | | | | | | | |
| | | | | | | | Total Demand | $ Per |
| 1 | 2 | 3 | 4 | 5 | 6 | 7 | Cost | Customer |
| $50,351 | $50,351 | $50,351 | $52,990 | $52,990 | $52,990 | $57,968 | $367,990 | $ 365.91 |
| $12,657 | $12,657 | $12,657 | $10,049 | $10,049 | $10,049 | $ 7,463 | $ 75,582 | $ 563.34 |
| $ 2,697 | $ 2,697 | $ 2,697 | $ 2,141 | $ 2,141 | $ 2,141 | $ 1,590 | $ 16,105 | $ 563.34 |
| $ 9 | $ 9 | $ 9 | $ 7 | $ 7 | $ 7 | $ 5 | $ 53 | $ 563.34 |
| $ 559 | $ 559 | $ 559 | $ 379 | $ 379 | $ 379 | $ 497 | $ 3,312 | $ 386.46 |
| $ 445 | $ 445 | $ 445 | $ 302 | $ 302 | $ 302 | $ 395 | $ 2,635 | $ 386.46 |
| $ 276 | $ 276 | $ 276 | $ 187 | $ 187 | $ 187 | $ 245 | $ 1,635 | $ 386.46 |
| $ 7 | $ 7 | $ 7 | $ 5 | $ 5 | $ 5 | $ 6 | $ 43 | $ 386.46 |
| $ 14 | $ 14 | $ 14 | $ 11 | $ 11 | $ 11 | $ 22 | $ 97 | $ 258.26 |
| $ 44 | $ 44 | $ 44 | $ 28 | $ 28 | $ 28 | $ 67 | $ 282 | $ 248.96 |
| $ 3 | $ 3 | $ 3 | $ 2 | $ 2 | $ 2 | $ 5 | $ 20 | $ 258.26 |
| $ 1,708 | $ 1,708 | $ 1,708 | $ 2,689 | $ 2,689 | $ 2,689 | $ 521 | $ 13,711 | $1,181.70 |
| $ 17 | $ 17 | $ 17 | $ 7 | $ 7 | $ 7 | $ 9 | $ 81 | $ 535.06 |
| $ 13 | $ 13 | $ 13 | $ 5 | $ 5 | $ 5 | $ 6 | $ 59 | $ 535.06 |
| $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| $68,801 | $68,801 | $68,801 | $68,801 | $68,801 | $68,801 | $68,801 | $481,605 | |

PC 7

PacifiCorp
Oregon Circuit Model Study
Dedicated Circuit Trunk Costs
For Large Customers

| | | Voltage Delivery | |
|---|---|---|---|
| | | Large GS + 4 MW | |
| | | Poles | Conductor |
| 1 | Construction Cost Per Mile | $64,984 | $110,173 |
| 2 | Average Trunk Length | 0.67 miles | |
| 3 | Total Construction Cost | $43,539 | $73,816 |
| 5 | Customer Peak Demand (Sec) | 3,591 kW | |
| 4 | Customer Peak Demand (Pri) | 8,630 kW | |
| 7 | Demand Cost $/kW (Sec) | $12.13 | $20.56 |
| 6 | Demand Cost $/kW (Pri) | $5.04 | $8.55 |

Construction Costs for Distribution Line type - 3 Phase -795 AAC & 477 AAC.

Line 1 - 'System-wide Pole and Conductor Costs' (PC 4)
Line 2 - Distribution Engineering Studies
Line 3 - Line 1 multiplied by Line 2
Line 4 - 'Circuit Distribution Model Inputs & Calculations' (PC 2)
Line 5 - Line 3 divided by Line 4

PC 8

PacifiCorp
Oregon Circuit Model Study
Trunk All Demand Costs
Outer Branches Commitment & Demand
Three Phase As Needed

| Line | Class | (A) Commitment $/Customer Poles | (B) Conductor | (C) Demand $/Dist. kW Poles | (D) Conductor | (E) Typical circuit Customers | (F) kW | (G) =(C)*(F) Demand $/circuit Poles | (H) =(D)*(F) Conductor |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Res - Schedule 4 (sec) | $ 841.90 | $ 365.91 | $ 191.87 | $ 254.38 | 1,005.7 | 2,288.76 | $ 439,152 | $ 582,222 |
| 2 | GS - Schedule 23 - 0-15 kW (sec) | $ 1,296.15 | $ 563.34 | $ 286.09 | $ 332.38 | 134.2 | 170.48 | $ 48,771 | $ 56,664 |
| 3 | GS - Schedule 23 - 15+ kW (sec) | $ 1,296.15 | $ 563.34 | $ 286.09 | $ 332.38 | 28.6 | 184.21 | $ 52,700 | $ 61,228 |
| 4 | GS - Schedule 23 - Primary (pri) | $ 1,296.15 | $ 563.34 | $ 286.09 | $ 332.38 | 0.1 | 0.56 | $ 159 | $ 185 |
| 5 | GS - Schedule 28 - 0-50 kW (sec) | $ 889.19 | $ 386.46 | $ 202.58 | $ 261.28 | 8.6 | 131.23 | $ 26,584 | $ 34,287 |
| 6 | GS - Schedule 28 - 51-100 kW (sec) | $ 889.19 | $ 386.46 | $ 202.58 | $ 261.28 | 6.8 | 196.76 | $ 39,859 | $ 51,408 |
| 7 | GS - Schedule 28 - 100 + kW (sec) | $ 889.19 | $ 386.46 | $ 202.58 | $ 261.28 | 4.2 | 276.44 | $ 56,002 | $ 72,228 |
| 8 | GS - Schedule 28 - Primary (pri) | $ 889.19 | $ 386.46 | $ 202.58 | $ 261.28 | 0.1 | 5.90 | $ 1,195 | $ 1,541 |
| 9 | GS - Schedule 30 - 0-300 kW (sec) | $ 594.22 | $ 258.26 | $ 141.52 | $ 210.47 | 0.4 | 49.33 | $ 6,981 | $ 10,382 |
| 10 | GS - Schedule 30 - 300+ kW (sec) | $ 572.81 | $ 248.96 | $ 137.30 | $ 206.49 | 1.1 | 297.70 | $ 40,874 | $ 61,471 |
| 11 | GS - Schedule 30 - Primary (pri) | $ 594.22 | $ 258.26 | $ 141.52 | $ 210.47 | 0.1 | 20.84 | $ 2,949 | $ 4,385 |
| 12 | Irrigation - Sch 41 | $ 2,718.91 | $ 1,181.70 | $ 573.90 | $ 586.62 | 11.6 | 88.61 | $ 50,853 | $ 51,980 |
| 13 | LPS - Schedule 48 - 1 - 4 MW (sec) | $ 1,231.08 | $ 535.06 | $ 274.88 | $ 318.09 | 0.2 | 120.14 | $ 33,025 | $ 38,217 |
| 14 | LPS - Schedule 48 - 1 - 4 MW (pri) | $ 1,231.08 | $ 535.06 | $ 274.88 | $ 318.09 | 0.1 | 135.45 | $ 37,233 | $ 43,087 |
| 15 | Total - | $ 922.10 | $ 400.76 | $ 210.86 | $ 269.59 | 1,201.7 | 3,966.39 | $ 836,335 | $ 1,069,285 |
| 16 | | | | | | | | | |
| 17 | Large GS + 4 MW (sec) | $ - | $ - | $ 12.13 | $ 20.56 | - | 3,590.54 | $ 43,539 | $ 73,816 |
| 18 | Large GS + 4 MW (pri) | $ - | $ - | $ 5.04 | $ 8.55 | - | 8,630.13 | $ 43,539 | $ 73,816 |
| | | | | | | | | $ 923,413 | $ 1,216,917 |

| | Commitment | Demand | Total |
|---|---|---|---|
| Poles | $ 1,108,097 | $ 923,413 | $ 2,031,511 |
| Conductor | $ 481,605 | $ 1,216,917 | $ 1,698,522 |
| Total | $ 1,589,702 | $ 2,140,330 | $ 3,730,033 |

Source : Column (A) - Pole Commitment Calculations' (PC 6)
Column (B) - Conductor Commitment Calculations' (PC 6)
Column (C) - Pole Demand Calculations' (PC 5)
Column (D) - Conductor Demand Calculations' (PC 5)
Column (E) - Average Customers by Hypothetical Circuit Branch' (PC 3)
Column (F) - Circuit kW Load by Branch' (PC 3)

XFMR 1

PacifiCorp
Oregon Marginal Cost Study
Transformer Demand and Commitment Costs

| Line | Customer Type | (A) Percent of Customers | (B) Dollars / Tran. | (C) Weighted $ / Tran. (A) x (B) | (D) # Cust. / Tran. | (E) Transformer $ / Cust. (C) / (D) | (F) Average Customers | (G) Tot. Trans. Commitment $ (E) x (F) | (H) Weighted $ / kW | (I) Transformer Peak kW | (J) Tot. Trans. Demand $ (H) x (I) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Res - Schedule 4 | 100.00% | 339.87 | 339.87 | 4.12 | 82.56 | 513,581 | 42,401,247 | 1.57 | 3,378,644 | 5,315,624 |
| 2 | | | | | | | | | | | |
| 3 | GS - Schedule 23 | | | | | | | | | | |
| 4 | 1 Phase | 80.77% | 339.87 | 274.50 | 2.41 | 113.67 | | | | | |
| 5 | 3 Phase | 19.23% | 928.50 | 178.59 | 3.00 | 59.47 | | | | | |
| 6 | 0-15 kW | | | | | 173.14 | 70,880 | 12,272,163 | 1.57 | 729,955 | 1,148,440 |
| 7 | | | | | | | | | | | |
| 8 | 1 Phase | 54.22% | 339.87 | 184.27 | 2.41 | 76.31 | | | | | |
| 9 | 3 Phase | 45.78% | 928.50 | 425.10 | 3.00 | 141.55 | | | | | |
| 10 | 15+ kW | | | | | 217.86 | 15,103 | 3,290,339 | 1.57 | 412,650 | 649,222 |
| 11 | | | | | | | | | | | |
| 12 | GS - Schedule 28 | | | | | | | | | | |
| 13 | 1 Phase | 29.27% | 339.87 | 99.48 | 1.37 | 72.71 | | | | | |
| 14 | 3 Phase | 70.73% | 928.50 | 656.74 | 1.25 | 525.13 | | | | | |
| 15 | 0-50 kW | | | | | 597.84 | 4,630 | 2,767,976 | 1.57 | 191,574 | 301,404 |
| 16 | | | | | | | | | | | |
| 17 | 1 Phase | 14.60% | 339.87 | 49.64 | 1.37 | 36.28 | | | | | |
| 18 | 3 Phase | 85.40% | 928.50 | 792.90 | 1.25 | 634.01 | | | | | |
| 19 | 51-100 kW | | | | | 670.29 | 3,683 | 2,468,858 | 1.57 | 390,191 | 613,888 |
| 20 | | | | | | | | | | | |
| 21 | 1 Phase | 2.48% | 339.87 | 8.43 | 1.37 | 6.16 | | | | | |
| 22 | 3 Phase | 97.52% | 928.50 | 905.47 | 1.25 | 724.02 | | | | | |
| 23 | 100 + kW | | | | | 730.18 | 2,286 | 1,669,024 | 1.57 | 486,664 | 765,668 |
| 24 | | | | | | | | | | | |
| 25 | GS - Schedule 30 | | | | | | | | | | |
| 26 | 1 Phase | 0.42% | 339.87 | 1.43 | 1.52 | 0.94 | | | | | |
| 27 | 3 Phase | 99.58% | 928.50 | 924.59 | 1.07 | 865.94 | | | | | |
| 28 | 0-300 kW | | | | | 866.88 | 200 | 173,577 | 1.57 | 42,766 | 67,284 |
| 29 | | | | | | | | | | | |
| 30 | 1 Phase | 0.06% | 339.87 | 0.19 | 1.52 | 0.12 | | | | | |
| 31 | 3 Phase | 99.94% | 928.50 | 927.98 | 1.07 | 869.11 | | | | | |
| 32 | 300+ kW | | | | | 869.23 | 606 | 526,552 | 1.57 | 247,527 | 389,434 |
| 33 | | | | | | | | | | | |
| 34 | LPS - Schedule 48 | | | | | | | | | | |
| 35 | 1 - 4 MW (sec) | 100.00% | 928.50 | 928.50 | 1.11 | 838.23 | 82 | 68,662 | 1.57 | 105,438 | 165,886 |
| 36 | > 4 MW (sec) | 100.00% | 928.50 | 928.50 | 1.11 | 838.23 | 4 | 3,425 | 1.57 | 26,117 | 41,089 |
| 37 | | | | | | | | | | | |
| 38 | Schedule 41- Irrigation | | | | | | | | | | |
| 39 | 1 Phase | 15.70% | 339.87 | 53.35 | 1.23 | 43.31 | | | | | |
| 40 | 3 Phase | 84.30% | 928.50 | 782.75 | 1.18 | 664.94 | | | | | |
| 41 | Total | | | | | 708.25 | 7,887 | 5,586,075 | 1.57 | 186,770 | 293,845 |
| 42 | | | | | | | | | | | |
| 43 | Lighting | 100.00% | 339.87 | 339.87 | 3.01 | 112.81 | 7,437 | 838,975 | 1.57 | 11 | 18 |

XFMR2

PacifiCorp
Oregon Marginal Cost Study
Calculation of Escalation Factors for Transformers
(Regression weighted by number of transformer banks)

| Line | Description | (A) Demand Related | (B) Adjusted for System Power Factor of 0.95 | (C) Commitment Related | (D) Indexed to 2023 | (E) Annualized $ @ 7.21% |
|---|---|---|---|---|---|---|
| | | | (A) / 0.95 | | (B) or (C) x 1.0459 | (D) x 7.21% |
| 1 | 1 Phase $/kW | $19.82 | $20.86 | | $21.82 | $1.57 |
| 2 | | | | | | |
| 3 | 3 Phase $/kW | $19.82 | $20.86 | | $21.82 | $1.57 |
| 4 | | | | | | |
| 5 | 1 Phase | | | $4,506.90 | $4,713.84 | $339.87 |
| 6 | $/Transformer | | | | | |
| 7 | | | | | | |
| 8 | 3 Phase | | | $7,805.77 | | |
| 9 | Dummy Variable | | | | | |
| 10 | | | | | | |
| 11 | 3 Phase | | | $12,312.67 | $12,878.01 | $928.50 |
| 12 | $/Transformer | | | | | |

| Escalation Factor 2023-2025 |
|---|
| 1.046 |

Dist OM

PacifiCorp
Oregon Marginal Cost Study
Distribution O&M Expense
Loading Factor as a Percent of Dist. Plant
(Excluding Meters and St Ltg)

| Line | Description | (A) 2013 | (B) 2014 | (C) 2015 | (D) 2016 | (E) 2017 | (F) 2018 | (G) 2019 | (H) 2020 | (I) 2021 | (J) 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Distribution O & M Expenses | | | | | | | | | | |
| 1 | Total Distribution O & M Expense | 68,689,786 | 70,580,614 | 69,136,197 | 61,535,374 | 61,513,756 | 61,139,370 | 68,212,991 | 83,124,296 | 90,983,613 | 114,178,049 |
| 2 | Less: | | | | | | | | | | |
| 3 | 586 Meter Expense | 2,991,325 | 3,120,160 | 2,616,262 | 1,645,292 | 1,079,103 | 883,546 | 655,758 | 1,279,281 | 1,305,324 | 1,394,304 |
| 4 | 587 Customer Installation Expense | 4,352,166 | 4,244,231 | 4,157,616 | 5,227,622 | 5,089,251 | 5,107,333 | 5,763,027 | 6,702,788 | 6,553,641 | 6,997,994 |
| 5 | 597 Main. of Meters | 1,628,742 | 1,653,908 | 1,198,881 | 10,098 | 59,787 | 85,408 | 231,001 | 235,870 | 158,233 | 185,682 |
| 6 | | | | | | | | | | | |
| 7 | Total Adjusted Distribution O & M Expense | | | | | | | | | | |
| 8 | Line 1 - (Lines 3 through 5) | 59,717,552 | 61,562,315 | 61,163,438 | 54,652,362 | 55,285,614 | 55,063,083 | 61,563,205 | 74,906,357 | 82,966,414 | 105,600,068 |
| 9 | | | | | | | | | | | |
| 10 | | | | | | | | | | | |
| 11 | Distribution Plant | | | | | | | | | | |
| 12 | Total Distribution Plant | 1,823,007,262 | 1,866,641,345 | 1,916,622,378 | 1,970,302,647 | 2,040,304,183 | 2,128,892,665 | 2,179,547,153 | 2,311,229,537 | 2,411,640,782 | 2,512,503,433 |
| 13 | Less: | | | | | | | | | | |
| 14 | 370 Meters | 59,706,364 | 60,110,283 | 60,993,623 | 62,541,755 | 65,791,804 | 76,927,946 | 90,849,203 | 96,302,523 | 97,893,679 | 101,011,391 |
| 15 | | | | | | | | | | | |
| 16 | Adjusted Distribution Plant | | | | | | | | | | |
| 17 | Line 12 - Line 14 | 1,763,300,899 | 1,806,531,062 | 1,855,628,755 | 1,907,760,892 | 1,974,512,380 | 2,051,964,719 | 2,088,697,950 | 2,214,927,014 | 2,313,747,103 | 2,411,492,042 |
| 18 | | | | | | | | | | | |
| 19 | | | | | | | | | | | |
| 20 | O & M Expense Loading Factor | | | | | | | | | | |
| 21 | Distribution O & M Loading | 3.39% | 3.41% | 3.30% | 2.86% | 2.80% | 2.68% | 2.95% | 3.38% | 3.59% | 4.38% |
| 22 | Line 8 / Line 17 | | | | | | | | | | |
| 23 | | | | | | | | | | | |
| 24 | Average Distribution O & M Loading | | | | | | | | | | |
| 25 | Average of Line 22 | 3.27% | | | | | | | | | |
| 26 | | | | | | | | | | | |
| 27 | Distribution Annual Charge | 7.21% | | | | | | | | | |
| 28 | | | | | | | | | | | |
| 29 | Annualized Distribution O & M Loading Factor | | | | | | | | | | |
| 30 | Line 24 / Line 27 | 45.35% | | | | | | | | | |

Footnotes:
Source: FERC Form 1 (State of Oregon) & Results of Operations

Services

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Service Drop Costs

| Line | Load Class | (A) Customers | (B) % 1 & 3 Phase | (C) Overhead Service Drop Cost | (D) Underground Service Drop Cost | (E) % Overhead | (F) % Underground | (G) Weighted Service Drop Cost | (H) Weighted Service Drop Cost 1 & 3 Phase | (I) Weighted Service Drop Cost 1 Phase | (J) Weighted Service Drop Cost 3 Phase |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Res - Schedule 4 | 533,013 | 100.00% | | | | | 786 | 786 | 786 | |
| 2 | Annualized - Line 1 x 7.21% | | | | | | | | 57 | 57 | |
| 3 | | | | | | | | | | | |
| 4 | GS - Schedule 23 | | | | | | | | | | |
| 5 | 0-15 kW | | | | | | | | | | |
| 6 | kW = 0, 1 Phase | 3,724 | 5.24% | 976 | 826 | 60.7% | 39.3% | 917 | 48 | 59 | |
| 7 | kW = 0, 3 Phase | 4 | 0.01% | 1,187 | 1,123 | 60.7% | 39.3% | 1,162 | 0 | | 0 |
| 8 | kW > 1, 1 Phase | 53,708 | 75.53% | 1,111 | 918 | 60.7% | 39.3% | 1,035 | 782 | 968 | |
| 9 | kW > 1, 3 Phase | 13,673 | 19.23% | 1,309 | 1,203 | 60.7% | 39.3% | 1,268 | 244 | | 1,267 |
| 10 | Total 0-15 kW | 71,109 | 100.00% | | | | | | 1,074 | 1,028 | 1,268 |
| 11 | Annualized - Line 10 x 7.21% | | | | | | | | 77 | 74 | 91 |
| 12 | | | | | | | | | | | |
| 13 | 15+ kW | | | | | | | | | | |
| 14 | 1 Phase | 8,215 | 54.22% | 2,025 | 1,628 | 60.7% | 39.3% | 1,869 | 1,013 | 1,869 | |
| 15 | 3 Phase | 6,937 | 45.78% | 2,321 | 1,933 | 60.7% | 39.3% | 2,168 | 993 | | 2,168 |
| 16 | Total 15+ kW | 15,152 | 100.00% | | | | | | 2,006 | 1,869 | 2,168 |
| 17 | Annualized - Line 16 x 7.21% | | | | | | | | 145 | 135 | 156 |
| 18 | | | | | | | | | | | |
| 19 | GS - Schedule 28 | | | | | | | | | | |
| 20 | 0-50 kW | | | | | | | | | | |
| 21 | 1 Phase | 1,328 | 29.24% | 2,025 | 1,628 | 39.4% | 60.6% | 1,785 | 522 | 1,785 | |
| 22 | 3 Phase | 3,213 | 70.76% | 2,321 | 1,933 | 39.4% | 60.6% | 2,086 | 1,476 | | 2,086 |
| 23 | Total 0-50 kW | 4,541 | 100.00% | | | | | | 1,998 | 1,785 | 2,086 |
| 24 | Annualized - Line 23 x 7.21% | | | | | | | | 144 | 129 | 150 |
| 25 | | | | | | | | | | | |
| 26 | 51-100 kW | | | | | | | | | | |
| 27 | 1 Phase | 527 | 14.59% | 2,025 | 1,628 | 39.4% | 60.6% | 1,785 | 260 | 1,785 | |
| 28 | 3 Phase | 3,086 | 85.41% | 2,321 | 1,933 | 39.4% | 60.6% | 2,086 | 1,782 | | 2,086 |
| 29 | Total 51-100 kW | 3,613 | 100.00% | | | | | | 2,042 | 1,785 | 2,086 |
| 30 | Annualized - Line 29 x 7.21% | | | | | | | | 147 | 129 | 150 |
| 31 | | | | | | | | | | | |
| 32 | 100 + kW | | | | | | | | | | |
| 33 | 1 Phase | 56 | 2.50% | 3,745 | 4,150 | 39.4% | 60.6% | 3,991 | 100 | 3,991 | |
| 34 | 3 Phase | 2,187 | 97.50% | 4,106 | 5,035 | 39.4% | 60.6% | 4,669 | 4,552 | | 4,669 |
| 35 | Total 100 + kW | 2,243 | 100.00% | | | | | | 4,652 | 3,991 | 4,669 |
| 36 | Annualized - Line 35 x 7.21% | | | | | | | | 335 | 288 | 337 |
| 37 | | | | | | | | | | | |
| 38 | GS - Schedule 30 | | | | | | | | | | |
| 39 | | | | | | | | | | | |
| 40 | 0-300 kW | | | | | | | | | | |
| 41 | 1 Phase | 1 | 0.50% | 3,745 | 4,150 | 17.0% | 83.0% | 4,081 | 21 | | |
| 42 | 3 Phase | 198 | 99.50% | 4,106 | 5,035 | 17.0% | 83.0% | 4,877 | 4,853 | | |
| 43 | Total 0-300 kW | 199 | 100.00% | | | | | | 4,873 | | |
| 44 | Annualized - Line 43 x 7.21% | | | | | | | | 351 | | |
| 45 | | | | | | | | | | | |
| 46 | 300+ kW | | | | | | | | | | |
| 47 | 1 Phase | - | 0.00% | 9,834 | 8,163 | 17.0% | 83.0% | 8,447 | - | | |
| 48 | 3 Phase | 600 | 100.00% | 9,834 | 8,163 | 17.0% | 83.0% | 8,447 | 8,447 | | |
| 49 | Total 300+ kW | 600 | 100.00% | | | | | | 8,447 | | |
| 50 | Annualized - Line 49 x 7.21% | | | | | | | | 609 | | |
| 51 | | | | | | | | | | | |
| 52 | LPS - Schedule 48 | | | | | | | | | | |
| 53 | 1 - 4 MW (sec) | 81 | 100.00% | | 30,522 | 0.0% | 100.0% | 30,522 | 30,522 | | |
| 54 | Annualized - Line 53 x 7.21% | | | | | | | | 2,201 | | |
| 55 | | | | | | | | | | | |
| 56 | > 4 MW (sec) | 4 | 100.00% | | 30,522 | 0.0% | 100.0% | 30,522 | 30,522 | | |
| 57 | Annualized - Line 56 x 7.21% | | | | | | | | 2,201 | | |

Meters

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Meter Costs

| Line | Load Class | (A) Customers | (B) % of Customers 1 & 3 Phase | (C) % of Customers 1 Phase | (D) % of Customers 3 Phase | (E) Metering Cost | (F) Weighted Metering Cost 1 & 3 Phase | (G) Weighted Metering Cost 1 Phase | (H) Weighted Metering Cost 3 Phase |
|---|---|---|---|---|---|---|---|---|---|
| | | | (A) / (A,Ttl) | (A) / 1Ø | (A) / 3Ø | | (B) x (E) | (C) x (E) | (D) x (E) |
| 1 | Res - Schedule 4 | 533,013 | 100.00% | 100.00% | | 231.80 | 231.80 | 231.80 | |
| 3 | Annualized - (Line 1) x 7.21% | | | | | | 16.71 | 16.71 | |
| 4 | | | | | | | | | |
| 5 | GS - Schedule 23 | | | | | | | | |
| 6 | 0-15 kW | | | | | | | | |
| 7 | kW = 0, 1 Phase | 3,724 | 5.24% | 6.48% | | 221.73 | 11.61 | 14.38 | |
| 8 | kW = 0, 3 Phase | 4 | 0.01% | | 0.03% | 347.24 | 0.02 | | 0.10 |
| 9 | kW > 1, 1 Phase | 53,708 | 75.53% | 93.52% | | 221.73 | 167.47 | 207.36 | |
| 10 | kW > 1, 3 Phase | 13,673 | 19.23% | | 99.97% | 347.24 | 66.77 | | 347.14 |
| 11 | Total 0-15 kW | 71,109 | 100.00% | 100.00% | 100.00% | | 245.87 | 221.74 | 347.24 |
| 12 | Annualized - (Line 11) x 7.21% | | | | | | 17.73 | 15.99 | 25.04 |
| 13 | | | | | | | | | |
| 14 | 15+ kW | | | | | | | | |
| 15 | 1 Phase | 8,215 | 54.22% | 100.00% | | 221.73 | 120.22 | 221.73 | |
| 16 | 3 Phase W/O KVAR | 3,591 | 23.70% | | 51.77% | 347.24 | 82.30 | | 179.75 |
| 17 | 3 Phase With KVAR | 3,346 | 22.08% | | 48.23% | 347.24 | 76.68 | | 167.49 |
| 18 | Total 15+ kW | 15,152 | 100.00% | 100.00% | 100.00% | | 279.20 | 221.73 | 347.24 |
| 19 | Annualized - (Line 18) x 7.21% | | | | | | 20.13 | 15.99 | 25.04 |
| 20 | | | | | | | | | |
| 21 | Primary | | | | | | | | |
| 22 | 12.47 KV 4-wire Wye | 50 | 100.00% | | 100.00% | 16,090.36 | 16,090.36 | | 16,090.36 |
| 23 | Annualized - (Line 22) x 7.21% | | | | | | 1,160.11 | | 1,160.11 |
| 24 | | | | | | | | | |

| Line | Load Class | Customers | 1 & 3 Phase | 1 Phase | 3 Phase | Metering Cost | 1 & 3 Phase | 1 Phase | 3 Phase |
|---|---|---|---|---|---|---|---|---|---|
| 25 | GS - Schedule 28 | | | | | | | | |
| 26 | 0-50 kW | | | | | | | | |
| 27 | kW = 0, 1 Phase | 7 | 0.15% | 0.53% | | 221.73 | 0.34 | 1.17 | |
| 28 | kW = 0, 3 Phase | 10 | 0.22% | | 0.31% | 347.24 | 0.76 | | 1.08 |
| 29 | kW > 1, 1 Phase | 1,321 | 29.09% | 99.47% | | 221.73 | 64.50 | 220.57 | |
| 30 | kW > 1, 3 Phase | 3,203 | 70.54% | | 99.69% | 347.24 | 244.93 | | 346.16 |
| 31 | Total 0-50 kW | 4,541 | 100.00% | 100.00% | 100.00% | | 310.53 | 221.74 | 347.24 |
| 32 | Annualized - (Line 31) x 7.21% | | | | | | 22.39 | 15.99 | 25.04 |
| 33 | | | | | | | | | |
| 34 | 51-100 kW | | | | | | | | |
| 35 | 1 Phase | 527 | 14.59% | 100.00% | | 221.73 | 32.34 | 221.73 | |
| 36 | 3 Phase W/O KVAR | 1,431 | 39.61% | | 46.37% | 347.24 | 137.53 | | 161.02 |
| 37 | 3 Phase With KVAR | 1,655 | 45.81% | | 53.63% | 347.24 | 159.06 | | 186.22 |
| 38 | Total 51-100 kW | 3,613 | 100.00% | 100.00% | 100.00% | | 328.93 | 221.73 | 347.24 |
| 39 | Annualized - (Line 38) x 7.21% | | | | | | 23.72 | 15.99 | 25.04 |
| 40 | | | | | | | | | |
| 41 | 100 + kW | | | | | | | | |
| 42 | 1 Phase | 56 | 2.50% | 100.00% | | 1,767.60 | 44.13 | 1,767.60 | |
| 43 | 3 Phase W/O KVAR | 936 | 41.73% | | 42.80% | 1,928.67 | 804.83 | | 825.44 |
| 44 | 3 Phase With KVAR | 1,251 | 55.77% | | 57.20% | 1,928.67 | 1,075.69 | | 1,103.23 |
| 45 | Total 100 + kW | 2,243 | 100.00% | 100.00% | 100.00% | | 1,924.65 | 1,767.60 | 1,928.67 |
| 46 | Annualized - (Line 45) x 7.21% | | | | | | 138.77 | 127.44 | 139.06 |
| 47 | | | | | | | | | |
| 48 | Primary | | | | | | | | |
| 49 | 12.47 KV 4-wire Wye | 59 | 100.00% | | 100.00% | 16,090.36 | 16,090.36 | | 16,090.36 |
| 50 | Annualized - (Line 49) x 7.21% | | | | | | 1,160.11 | | 1,160.11 |
| 51 | | | | | | | | | |

| Line | Load Class | Customers | 1 & 3 Phase | 1 Phase | 3 Phase | Metering Cost | 1 & 3 Phase | 1 Phase | 3 Phase |
|---|---|---|---|---|---|---|---|---|---|
| 52 | GS - Schedule 30 | | | | | | | | |
| 53 | 0-300 kW | | | | | | | | |
| 54 | 1 Phase | 1 | 0.50% | 100.00% | | 1,767.60 | 8.90 | 1,767.60 | |
| 55 | 3 Phase W/O KVAR | 43 | 21.50% | | 21.61% | 1,928.67 | 414.59 | | 416.69 |
| 56 | 3 Phase With KVAR | 155 | 78.00% | | 78.39% | 1,928.67 | 1,504.36 | | 1,511.98 |
| 57 | Total 0-300 kW | 199 | 100.00% | 100.00% | 100.00% | | 1,927.85 | 1,767.60 | 1,928.67 |
| 58 | Annualized - (Line 57) x 7.21% | | | | | | 139.00 | 127.44 | 139.06 |
| 59 | | | | | | | | | |
| 60 | 300+ kW | | | | | | | | |
| 61 | 1 Phase | - | 0.00% | 100.00% | | 2,325.07 | - | 2,325.07 | |
| 62 | 3 Phase W/O KVAR | 155 | 25.83% | | 25.83% | 1,928.67 | 498.24 | | 498.24 |
| 63 | 3 Phase With KVAR | 445 | 74.17% | | 74.17% | 1,928.67 | 1,430.43 | | 1,430.43 |
| 64 | Total 300+ kW | 600 | 100.00% | 100.00% | 100.00% | | 1,928.67 | 2,325.07 | 1,928.67 |
| 65 | Annualized - (Line 64) x 7.21% | | | | | | 139.06 | 167.64 | 139.06 |
| 66 | | | | | | | | | |
| 67 | Primary | | | | | | | | |
| 68 | 12.47 KV 4-wire Wye | 40 | 100.00% | | 100.00% | 16,090.36 | 16,090.36 | | 16,090.36 |
| 69 | Annualized - (Line 68) x 7.21% | | | | | | 1,160.11 | | 1,160.11 |
| 70 | | | | | | | | | |
| 71 | LPS - Schedule 48 | | | | | | | | |
| 72 | 1 - 4 MW (sec) | 81 | 100.00% | | 100.00% | 2,445.35 | 2,445.35 | | 2,445.35 |
| 73 | Annualized - (Line 72) x 7.21% | | | | | | 176.31 | | 176.31 |
| 74 | | | | | | | | | |
| 75 | 1 - 4 MW (pri) | 58 | 100.00% | | 100.00% | 16,090.36 | 16,090.36 | | 16,090.36 |
| 76 | Annualized - (Line 75) x 7.21% | | | | | | 1,160.11 | | 1,160.11 |
| 77 | | | | | | | | | |
| 78 | > 4 MW (sec) | 4 | 100.00% | | 100.00% | 2,445.35 | 2,445.35 | | 2,445.35 |
| 79 | Annualized - (Line 78) x 7.21% | | | | | | 176.31 | | 176.31 |
| 80 | | | | | | | | | |
| 81 | > 4 MW (pri) | 24 | 100.00% | | 100.00% | 16,090.36 | 16,090.36 | | 16,090.36 |
| 82 | Annualized - (Line 81) x 7.21% | | | | | | 1,160.11 | | 1,160.11 |
| 83 | | | | | | | | | |
| 84 | Trans (trn) | 7 | 100.00% | | 100.00% | 247,538.33 | 247,538.33 | | 247,538.33 |
| 85 | Annualized - (Line 84) x 7.21% | | | | | | 17,847.51 | | 17,847.51 |
| 86 | | | | | | | | | |

| Line | Load Class | Customers | 1 & 3 Phase | 1 Phase | 3 Phase | Metering Cost | 1 & 3 Phase | 1 Phase | 3 Phase |
|---|---|---|---|---|---|---|---|---|---|
| 87 | | | | | | | | | |
| 88 | Irrigation - Schedule 41 (Annual) | | | | | | | | |
| 89 | 0 - 50 kW | | | | | | | | |
| 90 | kW = 0, 1 Phase | - | 0.00% | 0.00% | | 221.73 | - | - | |
| 91 | kW = 0, 3 Phase | - | 0.00% | | 0.00% | 347.24 | - | | - |
| 92 | kW > 1, 1 Phase | 965 | 14.69% | 100.00% | | 221.73 | 32.57 | 221.73 | |
| 93 | kW > 1, 3 Phase | 4,255 | 64.78% | | 82.08% | 347.24 | 224.93 | | 285.02 |
| 94 | | | | | | | | | |
| 95 | 51 - 300 kW | | | | | | | | |
| 96 | 1 Phase | - | 0.00% | 0.00% | | 221.73 | - | - | |
| 97 | 3 Phase W/O KVAR | 147 | 2.24% | | 2.84% | 347.24 | 7.77 | | 9.85 |
| 98 | 3 Phase With KVAR | 763 | 11.62% | | 14.72% | 347.24 | 40.33 | | 51.11 |
| 99 | | | | | | | | | |
| 100 | > 300 kW | | | | | | | | |
| 101 | 1 Phase | - | 0.00% | 0.00% | | 2,325.07 | - | - | |
| 102 | 3 Phase W/O KVAR | 4 | 0.06% | | 0.08% | 1,928.67 | 1.17 | | 1.49 |
| 103 | 3 Phase With KVAR | 15 | 0.23% | | 0.29% | 1,928.67 | 4.40 | | 5.58 |
| 104 | Total Irrigation | 6,569 | 100.00% | 100.00% | 100.00% | 1,928.67 | 311.17 | 221.73 | 353.05 |
| 105 | | | | | | | 22.44 | 15.99 | 25.45 |
| 106 | | | | | | | | | |
| 107 | Primary | - | 100.00% | | 100.00% | - | - | | - |
| 108 | | | | | | | - | | - |
| 109 | | | | | | | | | |
| 110 | Lighting - Schedule 54 | 98 | 100.00% | | 100.00% | | 17.73 | | |
| 111 | | | | | | | | | |

Footnote:
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2023.

Meter&ServiceCost

PacifiCorp
Oregon Marginal Cost Study
Summary of Average Installed Costs
Meters

| Line | Load Class | (A) Metering Standard | (B) Meter Cost in 2023 Dollars | (C) Indexed to 2025 Dollars | (D) Percent Use | (E) Total Installed Cost per Meter |
|---|---|---|---|---|---|---|
| | Residential | | | | | |
| 1 | Small Load | DM221J | $212 | 221.73 | 49.36% | 109.45 |
| 2 | All Electric | DM221K | $231 | 241.61 | 50.64% | 122.35 |
| 3 | | | | | 100.00% | 231.80 |
| 4 | | | | | | |
| 5 | 0 - 15 kW | | | | | |
| 6 | kW = 0, 1 Phase | DM221J | $212 | 221.73 | 100.00% | 221.73 |
| 7 | | | | | | |
| 8 | kW = 0, 3 Phase | DM241D | $332 | 347.24 | 100.00% | 347.24 |
| 9 | | | | | | |
| 10 | kW > 1, 1 Phase | DM221J | $212 | 221.73 | 100.00% | 221.73 |
| 11 | | | | | | |
| 12 | kW > 1, 3 Phase | DM241D | $332 | 347.24 | 100.00% | 347.24 |
| 13 | | | | | | |
| 14 | | | | | | |
| 15 | 15 - 100 kW | | | | | |
| 16 | 1 Phase | DM221J | $212 | 221.73 | 100.00% | 221.73 |
| 17 | | | | | | |
| 18 | 3 Phase wo / KVAR | DM241D | $332 | 347.24 | 100.00% | 347.24 |
| 19 | | | | | | |
| 20 | 3 Phase with KVAR | DM241D | $332 | 347.24 | 100.00% | 347.24 |
| 21 | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | |
| | 100 - 300 kW | | | | | |
| | 1 Phase | DM231FBB | $1,690 | 1,767.60 | 100.00% | 1,767.60 |
| | | | | | | |
| | 3 Phase wo / KVAR | DM271DEC | $1,844 | 1,928.67 | 100.00% | 1,928.67 |
| | | | | | | |
| | 3 Phase with KVAR | DM271DEC | $1,844 | 1,928.67 | 100.00% | 1,928.67 |
| | | | | | | |
| | | | | | | |
| | 300-1000 kW | | | | | |
| | W/O KVAR, 1 Phase | DM231FFE | $2,223 | 2,325.07 | 100.00% | 2,325.07 |
| | | | | | | |
| | W/O KVAR, 3 Phase | DM271DEC | $1,844 | 1,928.67 | 100.00% | 1,928.67 |
| | | | | | | |
| | W/KVAR, 3 Phase | DM271DEC | $1,844 | 1,928.67 | 100.00% | 1,928.67 |
| | | | | | | |
| | | | | | | |
| | 1000 kW and over | | | | | |
| | Secondary Volt | DM271DEG | $2,338 | 2,445.35 | 100.00% | 2,445.35 |
| | | | | | | |
| | Primary Metering | | | | | |
| | '13.8 KV 3-wire | DM101ACBA | $11,109 | 11,619.07 | | 11,619.07 |
| | '12.47 KV 4-wire Wye | DM121ACJAD | $15,384 | 16,090.36 | | 16,090.36 |
| | 24.9 KV 4-wire Wye | DM121BFIAD | $15,060 | 15,751.48 | | 15,751.48 |
| | 35 KV 4-wire Wye | DM131BBAH | $21,819 | 22,820.83 | | 22,820.83 |
| | | | | | | |
| | Transmission | | 247,538 | | | |

| Escalation Factor |
|---|
| 2023 - 2025 |
| 1.0459 |

PacifiCorp
Oregon Marginal Cost Study
Summary of Average Installed Costs
Service Drops

| Line | Load Class | (A) Service Conductor | (B) Cost in 2023 Dollars | (C) Indexed to 2025 Dollars | (D) Percent Use | (E) Total Cost per Service |
|---|---|---|---|---|---|---|
| | | | | (B) x 1.0459 | | |
| | Residential | | | | | |
| 1 | OH - small load | #2 Triplex* | 642 | 671.48 | 29.9% | 200.59 |
| 2 | OH - all electric | 1/0 Triplex | 732 | 765.61 | 26.6% | 203.45 |
| 3 | UG - small load | 1/0 Triplex | 790 | 826.27 | 19.5% | 161.03 |
| 4 | UG - all electric | 4/0 Triplex | 878 | 918.31 | 24.1% | 221.00 |
| 5 | | | | | | 786.06 |
| 6 | 0 - 15 kW | | | | | |
| 7 | kW = 0, 1 Phase | OH - 1/0 Triplex | 933 | 975.84 | | |
| 8 | kW = 0, 1 Phase | UG - 1/0 Triplex | 790 | 826.27 | | |
| 9 | kW = 0, 3 Phase | OH - 1/0 Quadruplex | 1,135 | 1,187.11 | | |
| 10 | kW = 0, 3 Phase | UG - 1/0 Quadruplex | 1,074 | 1,123.31 | | |
| 11 | kW > 1, 1 Phase | OH - 4/0 Triplex | 1,062 | 1,110.76 | | |
| 12 | kW > 1, 1 Phase | UG - 4/0 Triplex | 878 | 918.31 | | |
| 13 | kW > 1, 3 Phase | OH - 4/0 Quadruplex | 1,252 | 1,309.49 | | |
| 14 | kW > 1, 3 Phase | UG - 4/0 Quadruplex | 1,150 | 1,202.80 | | |
| 15 | | | | | | |
| 16 | 16 - 100 kW | | | | | |
| 17 | 1 Phase | OH - 2-4/0 Triplex | 1,936 | 2,024.89 | | |
| 18 | 1 Phase | UG - 2-4/0 Triplex | 1,557 | 1,628.49 | | |
| 19 | 3 Phase | OH - 2-4/0 Quadruplex | 2,219 | 2,320.89 | | |
| 20 | 3 Phase | UG - 2-4/0 Quadruplex | 1,848 | 1,932.85 | | |
| 21 | | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 22 | 101 - 300 kW | | | | |
| 23 | 1 Phase | 3-500 & 350N | | 3,581 | 3,745.42 |
| 24 | 1 Phase | 3- 750 & 500 N | | 3,968 | 4,150.19 |
| 25 | 3 Phase | OH - 3-4/0 Quadruplex | | 3,926 | 4,106.26 |
| 26 | 3 Phase | 4-350 Quad | | 4,814 | 5,035.04 |
| 27 | | | | | |
| 28 | 301 - 1000 kW | | | | |
| 29 | 3 Phase | 3-750 kcmil Quad. | | 9,402 | 9,833.70 |
| 30 | 3 Phase | 4-750 kcmil Quad. | | 7,805 | 8,163.37 |
| 31 | | | | | |
| 32 | 1000 kW and Over | | | | |
| 33 | Secondary Voltage | 12-1000 kcmil Quad. | | 29,182 | 30,521.90 |
| 34 | Primary Voltage | --- | | --- | --- |
| 35 | | | | | |
| 36 | | | | Weighted % | |
| 37 | Residential Overhead % = | | 56.4% | | |
| 38 | % of Overhead Which Are Small Load= | | 52.9% | 29.9% | |
| 39 | % of Overhead Which Are All Electric= | | 47.1% | 26.6% | |
| 40 | | | | | |
| 41 | Residential Underground % = | | 43.6% | | |
| 42 | % of Underground Which Are Small Load= | | 44.7% | 19.5% | |
| 43 | % of Underground Which Are All Electric= | | 55.3% | 24.1% | |
| 44 | Total OH & UG | | | 100.0% | |

DistMeters

PacifiCorp
Oregon Marginal Cost Study
Distribution Meters Expense
Loading Factor

| Line | Description | (A) 2013 | (B) 2014 | (C) 2015 | (D) 2016 | (E) 2017 | (F) 2018 | (G) 2019 | (H) 2020 | (I) 2021 | (J) 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Distribution Meters Expenses | | | | | | | | | | |
| 1 | 586 Meter Expense | 2,991,325 | 3,120,160 | 2,616,262 | 1,645,292 | 1,079,103 | 883,546 | 655,758 | 1,279,281 | 1,305,324 | 1,394,304 |
| 2 | 597 Main. of Meters | 1,628,742 | 1,653,908 | 1,198,881 | 10,098 | 59,787 | 85,408 | 231,001 | 235,870 | 158,233 | 185,682 |
| 3 | | | | | | | | | | | |
| 4 | Total Adjusted Distribution Meters Expense | 4,620,067 | 4,774,068 | 3,815,143 | 1,655,390 | 1,138,890 | 968,955 | 886,759 | 1,515,150 | 1,463,558 | 1,579,986 |
| 5 | Line 1 + Line 2 | | | | | | | | | | |
| 6 | | | | | | | | | | | |
| 7 | | | | | | | | | | | |
| 8 | | | | | | | | | | | |
| 9 | Distribution Meters | | | | | | | | | | |
| 10 | 370 Meters | 59,706,364 | 60,110,283 | 60,993,623 | 62,541,755 | 65,791,804 | 76,927,946 | 90,849,203 | 96,302,523 | 97,893,679 | 101,011,391 |
| 11 | | | | | | | | | | | |
| 12 | | | | | | | | | | | |
| 13 | | | | | | | | | | | |
| 14 | Meters Expense Loading Factor | | | | | | | | | | |
| 15 | Meter O&M Loading | 7.74% | 7.94% | 6.25% | 2.65% | 1.73% | 1.26% | 0.98% | 1.57% | 1.50% | 1.56% |
| 16 | Line 4 / Line 10 | | | | | | | | | | |
| 17 | | | | | | | | | | | |
| 18 | Average Meter O&M Loading | 3.32% | | | | | | | | | |
| 19 | Average of Line 15 | | | | | | | | | | |
| 20 | | | | | | | | | | | |
| 21 | Distribution Annual Charge | 7.21% | | | | | | | | | |
| 22 | | | | | | | | | | | |
| 23 | Annualized Meter O&M Loading Factor | 46.02% | | | | | | | | | |
| 24 | Line 18 / Line 21 | | | | | | | | | | |

CustExpense

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer Accounting Expense
By Schedule
December 2025 Dollars

| Line | FERC Account | Description | Calculation Description | (A) Sch. 4 Residential | (B) Sch. 23 General Service | (C) Sch. 28 General Service | (D) Sch. 30 General Service | (E) Sch. 48 General Service | (F) Sch. 41 Irrigation | (G) Streetlighting | (H) Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | Average Number of Customers | 513,581 | 86,033 | 10,658 | 847 | 178 | 3,311 | 7,437 | 622,045 |
| 2 | | | Write-offs By Schedule | 7,450,315 | 191,361 | 247,890 | 125,789 | 326,979 | 125,324 | - | 8,467,658 |
| 3 | | | | | | | | | | | |
| 4 | | | | | | | | | | | |
| 5 | 901 | Supervision | Account 902 + 903 + 904 | 18,262,030 | 2,659,844 | 556,061 | 127,846 | 307,570 | 195,313 | 191,305 | 22,299,968 |
| 6 | 901 | | % of Total 902 + 903 + 904 | 81.89% | 11.93% | 2.49% | 0.57% | 1.38% | 0.88% | 0.86% | 100.00% |
| 7 | 901 | | Total 901 $ | 692,232 | 100,823 | 21,078 | 4,846 | 11,659 | 7,403 | 7,252 | 845,292 |
| 8 | 901 | | $ Per Customer | 1.35 | 1.17 | 1.98 | 5.72 | 65.50 | 2.24 | 0.98 | 1.36 |
| 9 | | | | | | | | | | | |
| 10 | 902 | Meter Reading Expense | 902 Weighting Factor | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | |
| 11 | 902 | | Weighted Customers | - | - | - | - | - | - | - | - |
| 12 | 902 | | % of Total $ | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 13 | 902 | | Total 902 $ | - | - | - | - | - | - | - | - |
| 14 | 902 | | $ Per Customer | - | - | - | - | - | - | - | - |
| 15 | | | | | | | | | | | |
| 16 | 903 | Cust. Receipts & Collect. | 903 Weighting Factor | 1.00 | 1.21 | 1.40 | 1.40 | 11.58 | 1.21 | 1.07 | |
| 17 | 903 | | Weighted Customers | 513,581 | 104,023 | 14,950 | 1,188 | 2,062 | 4,001 | 7,932 | 647,736 |
| 18 | 903 | | % of Total $ | 79.29% | 16.06% | 2.31% | 0.18% | 0.32% | 0.62% | 1.22% | 100.00% |
| 19 | 903 | | Total 903 $ | 12,387,179 | 2,508,948 | 360,591 | 28,656 | 49,735 | 96,490 | 191,305 | 15,622,905 |
| 20 | 903 | | $ Per Customer | 25.10 | 29.16 | 33.83 | 33.83 | 279.41 | 29.14 | 25.72 | 25.12 |
| 21 | | | | | | | | | | | |
| 22 | 904 | Uncollectibles | % of Write-offs | 87.99% | 2.26% | 2.93% | 1.49% | 3.86% | 1.48% | 0.00% | 100.00% |
| 23 | 904 | | Total 904 $ | 5,874,850 | 150,895 | 195,470 | 99,189 | 257,835 | 98,823 | - | 6,677,063 |
| 24 | 904 | | $ Per Customer | 11.44 | 1.75 | 18.34 | 117.11 | 1,448.51 | 29.85 | - | 10.73 |
| 25 | | | | | | | | | | | |
| 26 | 905 | Misc Cust Acct Expense | Account 902 + 903 + 904 | 18,262,030 | 2,659,844 | 556,061 | 127,846 | 307,570 | 195,313 | 191,305 | 22,299,968 |
| 27 | 905 | | % of Total 902 + 903 + 904 | 81.89% | 11.93% | 2.49% | 0.57% | 1.38% | 0.88% | 0.86% | 100.00% |
| 28 | 905 | | Total 905 $ | 3,683 | 536 | 112 | 26 | 62 | 39 | 39 | 4,497 |
| 29 | 905 | | $ Per Customer | 0.01 | 0.01 | 0.01 | 0.03 | 0.35 | 0.01 | 0.01 | 0.01 |
| 30 | | | | | | | | | | | |
| 31 | 907-910 | Supervision, Cust. Assist. | Average Number of customers | 513,581 | 86,033 | 10,658 | 847 | 178 | 3,311 | 7,437 | 622,045 |
| 32 | 907-910 | Info & Instructional Exp., | % of Total | 82.56% | 13.83% | 1.71% | 0.14% | 0.03% | 0.53% | 1.20% | 100.00% |
| 33 | 907-910 | Misc Cust Svc & Info Exp. | Total 907-910 $ | 4,792,775 | 802,866 | 99,461 | 7,904 | 1,661 | 30,896 | 69,403 | 5,804,967 |
| 34 | 907-910 | | $ Per Customer | 9.33 | 9.33 | 9.33 | 9.33 | 9.33 | 9.33 | 9.33 | 9.33 |
| 35 | | | | | | | | | | | |
| 36 | | | | | | | | | | | |
| 37 | 901 - 910 | | Total 901 - 910 $ | 23,750,719 | 3,564,069 | 676,712 | 140,622 | 320,951 | 233,652 | 267,999 | 28,954,724 |
| 38 | | | | | | | | | | | |
| 39 | | | $ Per Customer | 47.23 | 41.43 | 63.49 | 166.02 | 1,803.10 | 70.57 | 36.04 | 46.55 |

| | 2018 | 2019 | 2020 | 2021 | 2022 | Actual Year Adjusted 2025 |
|---|---|---|---|---|---|---|
| Customer Accounting | | | | | | |
| 901 Supervision | 776,328 | 712,826 | 706,833 | 699,844 | 884,456 | 845,292 |
| 902 Meter Reading Expense | 9,772,620 | 4,869,243 | 2,245,673 | 2,432,215 | 2,193,524 | 4,905,160 |
| 903 Cust Records & Collection | 15,706,759 | 15,074,984 | 13,295,839 | 12,573,679 | 12,954,582 | 15,622,905 |
| 904 Uncollectible Accounts | 4,639,879 | 5,061,708 | 6,263,999 | 5,394,731 | 8,652,079 | 6,677,063 |
| 905 Misc Cust Acct Expense | 4,809 | 5,606 | 8,479 | 830 | 47 | 4,497 |
| Total | 30,900,395 | 25,724,366 | 22,520,822 | 21,101,299 | 24,684,688 | 28,054,917 |
| Customer Service & Info Expense | | | | | | |
| 907 Supervision | 36,862 | 2,105 | 208 | (166) | 491 | 9,223 |
| 908 Cust Assistance Expense | 2,730,139 | 3,325,682 | 3,466,926 | 3,935,825 | 3,415,781 | 3,767,567 |
| 909 Info & Instructional Expense | 2,077,877 | 2,316,089 | 1,879,350 | 1,307,108 | 1,409,632 | 2,024,348 |
| 910 Misc Cust Svc & Info Expense | 12,955 | 1,416 | 541 | 394 | 1,242 | 3,829 |
| Total | 4,857,833 | 5,645,291 | 5,347,026 | 5,243,161 | 4,827,146 | 5,804,967 |
| Inflation Adjustment | 1.1701 | 1.1442 | 1.1188 | 1.0939 | 1.0697 | |

Source:
Source: State of Oregon results of operations

AG Expenses

PacifiCorp
Oregon Marginal Cost Study
Administrative & General Expense
Loading Factor

| Year | (A) Administrative and General Expenses ($000) | (B) Electric Plant in Service ($000) | (C) Admin. & General to Electric Plant In Service Loading Factor |
|---|---|---|---|
| | | | (A) / (B) |
| 2013 | 175,800 | 24,578,893 | 0.72% |
| 2014 | 103,887 | 25,826,088 | 0.40% |
| 2015 | 134,217 | 26,518,617 | 0.51% |
| 2016 | 129,633 | 27,064,435 | 0.48% |
| 2017 | 142,110 | 27,658,984 | 0.51% |
| 2018 | 135,363 | 28,221,394 | 0.48% |
| 2019 | 123,137 | 28,629,755 | 0.43% |
| 2020 | 291,921 | 30,542,983 | 0.96% |
| 2021 | 173,646 | 32,098,210 | 0.54% |
| 2022 | 260,189 | 32,845,783 | 0.79% |
| 10 Year Average A&G to EPIS Loading Factor | | | 0.58% |

Footnotes:
(A) FERC Form 1 Page 323, line 197
(B) FERC Form 1 Page 207, line 104

Charge

PacifiCorp
Oregon Marginal Cost Study
Calculation of Annual Charges

| Line | Description | (A) System Transmission | (B) Distribution |
|---|---|---|---|
| 1 | Levelized Income Taxes | 1.05% | 0.96% |
| 2 | Levelized Property Tax | 0.82% | 0.75% |
| 3 | Total | 1.87% | 1.71% |
| 4 | | | |
| 5 | Levelized Income & Property Taxes | $18.70 | $17.10 |
| 6 | (per $1,000 of Investment) | | |
| 7 | | | |
| 8 | Expected Life | 65 | 54 |
| 9 | | | |
| 10 | Nominal Interest Rate | 7.47% | 7.47% |
| 11 | | | |
| 12 | Present Value: Income ** | $248.17 | $224.37 |
| 13 | Taxes & Property Taxes per | (PV of $18.70 per year | (PV of $17.10 per year |
| 14 | $1,000 of Investment | | for 54 years at 7.47%) |
| 15 | | | |
| 16 | Removal Cost Per $1,000 Investment | $180.83 | $452.69 |
| 17 | | | |
| 18 | Present Value: Removal Cost | $1.68 | $9.28 |
| 19 | at End of Useful Life | (PV of $180.83 per year | (PV of $452.69 per year |
| 20 | | 65 years at 7.47%) | 54 years at 7.47%) |
| 21 | | | |
| 22 | Investment and Taxes | $1,249.85 | $1,233.65 |
| 23 | w/o PVCD (Line 12 + Line 18 + $1000) | | |
| 24 | | | |
| 25 | PVCD Factor | 0.035477 | 0.035221 |
| 26 | | | |
| 27 | PVCD $ (Line 22 x Line 25) | $44.34 | $43.45 |
| 28 | | | |
| 29 | Total (Line 22 + Line 27) | $1,294.19 | $1,277.10 |
| 30 | | | |
| 31 | EOY Annual Charge *** | $65.17 | $66.30 |
| 32 | | | |
| 33 | Annual Economic Carrying | 6.52% | 6.63% |
| 34 | Adm &Gen Expense Loading Factor | 0.58% | 0.58% |
| 35 | | | |
| 36 | Annual Econ Carrying + A&G Loading | 7.10% | 7.21% |

Footnotes:

From Financial Analysis -
** PV = Ln(5) x [1/r - (1/r)/(1+r)^a]

18.70*(1/0.0774-(1/0.0774)/(1+0.0774)^65)
17.10*(1/0.0774-(1/0.0774)/(1+0.0774)^54)

Where:
r = Nominal Interest Rate
a = Expected Investment Life

*** The Annual Charge Formula: AC% = Ln(11) x k x {1/[1 - 1/(1+k)^a]}/(1+k)

Where:
k = real interest rate = (1 + r) / (1 + i) - 1
i = inflation rate
a = expected investment life
r = nominal interest rate

| Financial Inputs | |
|---|---|
| Weighted Cost of Capital | 7.47% |
| Borrowing Rate | 7.47% |
| Average Inflation | 2.27% |
| | |
| Real Cost of Capital | |
| (1+0.0747)/(1+0.0227)-1 = | 5.08% |

| Levelized | |
|---|---|
| Income Taxes | |
| Transmission | 1.05% |
| Distribution | 0.96% |
| Property Taxes | |
| Transmission | 0.82% |
| Distribution | 0.75% |

Source:
Cost of Capital/Borrowing Rate: Revenue Requirement (OR Jurisdictional Allocation Model)
Income & Property Taxes: 2023 Use of Facilities Report
PacifiCorp's 2023 IRP

Iowa Curves

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor

Iowa Curve R 2 & 65 Year Average Life

Real Cost of Capital = 5.08%

| YEAR | (A) PVCD | (B) % RENEWED | (C) NUM1 | (D) DEM1 | (E) NUM1/DEM1 | (F) NUM2 | (G) DEM2 | (H) NUM2/DEM2 | (I) INSTANCE | (J) Iowa R 2.0 |
|---|---|---|---|---|---|---|---|---|---|---|
| | ((A) {yr-1} +(I)) / 100 | ((J,{yr-1})-(J)) * 100 | (B) | 1.0508 ^Year | (C) / (D) | (B) | 1.0508 ^62 | (F) / (G) | (E) - (H) | (Given) |
| | | | | | | | | | | 100.0000 |
| 1 | 0.00071 | 7.82% | 0.0782 | 1.05080 | 0.07442 | 0.0782 | 21.58746 | 0.00362 | 0.07080 | 99.9218 |
| 2 | 0.00205 | 15.63% | 0.1563 | 1.10418 | 0.14155 | 0.1563 | 21.58746 | 0.00724 | 0.13431 | 99.7655 |
| 3 | 0.00333 | 15.63% | 0.1563 | 1.16027 | 0.13471 | 0.1563 | 21.58746 | 0.00724 | 0.12747 | 99.6092 |
| 4 | 0.00459 | 16.32% | 0.1632 | 1.21921 | 0.13386 | 0.1632 | 21.58746 | 0.00756 | 0.12630 | 99.4460 |
| 5 | 0.00594 | 18.40% | 0.1840 | 1.28114 | 0.14362 | 0.1840 | 21.58746 | 0.00852 | 0.13510 | 99.2620 |
| 6 | 0.00722 | 18.40% | 0.1840 | 1.34622 | 0.13668 | 0.1840 | 21.58746 | 0.00852 | 0.12816 | 99.0780 |
| 7 | 0.00844 | 18.40% | 0.1840 | 1.41461 | 0.13007 | 0.1840 | 21.58746 | 0.00852 | 0.12155 | 98.8940 |
| 8 | 0.00979 | 21.60% | 0.2160 | 1.48647 | 0.14531 | 0.2160 | 21.58746 | 0.01001 | 0.13531 | 98.6780 |
| 9 | 0.01107 | 21.60% | 0.2160 | 1.56198 | 0.13829 | 0.2160 | 21.58746 | 0.01001 | 0.12828 | 98.4620 |
| 10 | 0.01229 | 21.60% | 0.2160 | 1.64132 | 0.13160 | 0.2160 | 21.58746 | 0.01001 | 0.12160 | 98.2460 |
| 11 | 0.01358 | 24.28% | 0.2428 | 1.72470 | 0.14078 | 0.2428 | 21.58746 | 0.01125 | 0.12953 | 98.0032 |
| 12 | 0.01486 | 25.17% | 0.2517 | 1.81231 | 0.13888 | 0.2517 | 21.58746 | 0.01166 | 0.12722 | 97.7515 |
| 13 | 0.01606 | 25.17% | 0.2517 | 1.90437 | 0.13217 | 0.2517 | 21.58746 | 0.01166 | 0.12051 | 97.4998 |
| 14 | 0.01729 | 27.18% | 0.2718 | 2.00111 | 0.13582 | 0.2718 | 21.58746 | 0.01259 | 0.12323 | 97.2280 |
| 15 | 0.01855 | 29.20% | 0.2920 | 2.10276 | 0.13886 | 0.2920 | 21.58746 | 0.01353 | 0.12534 | 96.9360 |
| 16 | 0.01973 | 29.20% | 0.2920 | 2.20958 | 0.13215 | 0.2920 | 21.58746 | 0.01353 | 0.11863 | 96.6440 |
| 17 | 0.02090 | 30.33% | 0.3033 | 2.32182 | 0.13063 | 0.3033 | 21.58746 | 0.01405 | 0.11658 | 96.3407 |
| 18 | 0.02212 | 33.72% | 0.3372 | 2.43977 | 0.13821 | 0.3372 | 21.58746 | 0.01562 | 0.12259 | 96.0035 |
| 19 | 0.02328 | 33.73% | 0.3373 | 2.56371 | 0.13157 | 0.3373 | 21.58746 | 0.01562 | 0.11594 | 95.6662 |
| 20 | 0.02438 | 33.72% | 0.3372 | 2.69394 | 0.12517 | 0.3372 | 21.58746 | 0.01562 | 0.10955 | 95.3290 |
| 21 | 0.02557 | 38.71% | 0.3871 | 2.83079 | 0.13675 | 0.3871 | 21.58746 | 0.01793 | 0.11881 | 94.9419 |
| 22 | 0.02669 | 38.71% | 0.3871 | 2.97459 | 0.13014 | 0.3871 | 21.58746 | 0.01793 | 0.11220 | 94.5548 |
| 23 | 0.02775 | 38.70% | 0.3870 | 3.12569 | 0.12381 | 0.3870 | 21.58746 | 0.01793 | 0.10589 | 94.1678 |
| 24 | 0.02886 | 42.91% | 0.4291 | 3.28447 | 0.13065 | 0.4291 | 21.58746 | 0.01988 | 0.11077 | 93.7387 |
| 25 | 0.02994 | 44.31% | 0.4431 | 3.45131 | 0.12839 | 0.4431 | 21.58746 | 0.02053 | 0.10786 | 93.2956 |
| 26 | 0.03095 | 44.31% | 0.4431 | 3.62664 | 0.12218 | 0.4431 | 21.58746 | 0.02053 | 0.10165 | 92.8525 |
| 27 | 0.03198 | 47.40% | 0.4740 | 3.81086 | 0.12438 | 0.4740 | 21.58746 | 0.02196 | 0.10242 | 92.3785 |
| 28 | 0.03300 | 50.49% | 0.5049 | 4.00445 | 0.12608 | 0.5049 | 21.58746 | 0.02339 | 0.10270 | 91.8736 |
| 29 | 0.03397 | 50.49% | 0.5049 | 4.20787 | 0.11999 | 0.5049 | 21.58746 | 0.02339 | 0.09660 | 91.3687 |
| 30 | 0.03491 | 52.20% | 0.5220 | 4.42162 | 0.11806 | 0.5220 | 21.58746 | 0.02418 | 0.09388 | 90.8467 |
| 31 | 0.03588 | 57.32% | 0.5732 | 4.64623 | 0.12337 | 0.5732 | 21.58746 | 0.02655 | 0.09682 | 90.2735 |
| 32 | 0.03678 | 57.33% | 0.5733 | 4.88225 | 0.11743 | 0.5733 | 21.58746 | 0.02656 | 0.09087 | 89.7002 |
| 33 | 0.03764 | 57.32% | 0.5732 | 5.13026 | 0.11173 | 0.5732 | 21.58746 | 0.02655 | 0.08518 | 89.1270 |
| 34 | 0.03854 | 64.83% | 0.6483 | 5.39087 | 0.12026 | 0.6483 | 21.58746 | 0.03003 | 0.09023 | 88.4787 |
| 35 | 0.03938 | 64.83% | 0.6483 | 5.66472 | 0.11445 | 0.6483 | 21.58746 | 0.03003 | 0.08441 | 87.8304 |
| 36 | 0.04017 | 64.83% | 0.6483 | 5.95248 | 0.10891 | 0.6483 | 21.58746 | 0.03003 | 0.07888 | 87.1821 |
| 37 | 0.04098 | 70.97% | 0.7097 | 6.25485 | 0.11346 | 0.7097 | 21.58746 | 0.03288 | 0.08059 | 86.4724 |
| 38 | 0.04175 | 73.02% | 0.7302 | 6.57259 | 0.11110 | 0.7302 | 21.58746 | 0.03383 | 0.07727 | 85.7422 |
| 39 | 0.04247 | 73.01% | 0.7301 | 6.90647 | 0.10571 | 0.7301 | 21.58746 | 0.03382 | 0.07189 | 85.0121 |
| 40 | 0.04318 | 77.46% | 0.7746 | 7.25730 | 0.10673 | 0.7746 | 21.58746 | 0.03588 | 0.07085 | 84.2375 |
| 41 | 0.04387 | 81.91% | 0.8191 | 7.62596 | 0.10741 | 0.8191 | 21.58746 | 0.03794 | 0.06947 | 83.4184 |
| 42 | 0.04451 | 81.91% | 0.8191 | 8.01335 | 0.10222 | 0.8191 | 21.58746 | 0.03794 | 0.06427 | 82.5993 |
| 43 | 0.04513 | 84.31% | 0.8431 | 8.42041 | 0.10013 | 0.8431 | 21.58746 | 0.03906 | 0.06107 | 81.7562 |
| 44 | 0.04574 | 91.50% | 0.9150 | 8.84816 | 0.10341 | 0.9150 | 21.58746 | 0.04239 | 0.06103 | 80.8412 |
| 45 | 0.04630 | 91.51% | 0.9151 | 9.29763 | 0.09842 | 0.9151 | 21.58746 | 0.04239 | 0.05603 | 79.9261 |
| 46 | 0.04681 | 91.51% | 0.9151 | 9.76993 | 0.09366 | 0.9151 | 21.58746 | 0.04239 | 0.05127 | 79.0110 |
| 47 | 0.04733 | 101.66% | 1.0166 | 10.26623 | 0.09902 | 1.0166 | 21.58746 | 0.04709 | 0.05193 | 77.9944 |
| 48 | 0.04780 | 101.66% | 1.0166 | 10.78774 | 0.09424 | 1.0166 | 21.58746 | 0.04709 | 0.04714 | 76.9778 |
| 49 | 0.04823 | 101.66% | 1.0166 | 11.33573 | 0.08968 | 1.0166 | 21.58746 | 0.04709 | 0.04259 | 75.9612 |
| 50 | 0.04864 | 109.65% | 1.0965 | 11.91157 | 0.09205 | 1.0965 | 21.58746 | 0.05079 | 0.04126 | 74.8647 |
| 51 | 0.04902 | 112.31% | 1.1231 | 12.51666 | 0.08973 | 1.1231 | 21.58746 | 0.05203 | 0.03770 | 73.7416 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 52 | 0.04935 | 112.31% | 1.1231 | 13.15249 | 0.08539 | 1.1231 | 21.58746 | 0.05203 | 0.03337 | 72.6185 |
| 53 | 0.04966 | 117.73% | 1.1773 | 13.82061 | 0.08518 | 1.1773 | 21.58746 | 0.05454 | 0.03065 | 71.4412 |
| 54 | 0.04993 | 123.17% | 1.2317 | 14.52267 | 0.08481 | 1.2317 | 21.58746 | 0.05706 | 0.02776 | 70.2095 |
| 55 | 0.05017 | 123.17% | 1.2317 | 15.26040 | 0.08071 | 1.2317 | 21.58746 | 0.05706 | 0.02366 | 68.9778 |
| 56 | 0.05037 | 125.87% | 1.2587 | 16.03560 | 0.07849 | 1.2587 | 21.58746 | 0.05831 | 0.02019 | 67.7191 |
| 57 | 0.05055 | 133.97% | 1.3397 | 16.85019 | 0.07951 | 1.3397 | 21.58746 | 0.06206 | 0.01745 | 66.3794 |
| 58 | 0.05068 | 133.97% | 1.3397 | 17.70615 | 0.07566 | 1.3397 | 21.58746 | 0.06206 | 0.01360 | 65.0397 |
| 59 | 0.05078 | 133.97% | 1.3397 | 18.60559 | 0.07201 | 1.3397 | 21.58746 | 0.06206 | 0.00995 | 63.7000 |
| 60 | 0.05085 | 144.25% | 1.4425 | 19.55073 | 0.07378 | 1.4425 | 21.58746 | 0.06682 | 0.00696 | 62.2575 |
| 61 | 0.05088 | 144.24% | 1.4424 | 20.54387 | 0.07021 | 1.4424 | 21.58746 | 0.06682 | 0.00339 | 60.8151 |
| 62 | 0.05088 | 144.25% | 1.4425 | 21.58746 | 0.06682 | 1.4425 | 21.58746 | 0.06682 | - | 59.3726 |
| 63 | 0.05085 | 151.14% | 1.5114 | 22.68407 | 0.06663 | 1.5114 | 21.58746 | 0.07001 | (0.00338) | 57.8612 |
| 64 | 0.05078 | 153.45% | 1.5345 | 23.83639 | 0.06438 | 1.5345 | 21.58746 | 0.07108 | (0.00671) | 56.3267 |
| 65 | 0.05069 | 153.45% | 1.5345 | 25.04723 | 0.06126 | 1.5345 | 21.58746 | 0.07108 | (0.00982) | 54.7922 |
| 66 | 0.05055 | 157.20% | 1.5720 | 26.31959 | 0.05973 | 1.5720 | 21.58746 | 0.07282 | (0.01309) | 53.2202 |
| 67 | 0.05039 | 160.95% | 1.6095 | 27.65658 | 0.05820 | 1.6095 | 21.58746 | 0.07456 | (0.01636) | 51.6107 |
| 68 | 0.05020 | 160.95% | 1.6095 | 29.06149 | 0.05538 | 1.6095 | 21.58746 | 0.07456 | (0.01917) | 50.0012 |
| 69 | 0.04998 | 162.24% | 1.6224 | 30.53777 | 0.05313 | 1.6224 | 21.58746 | 0.07515 | (0.02203) | 48.3788 |
| 70 | 0.04973 | 166.10% | 1.6610 | 32.08904 | 0.05176 | 1.6610 | 21.58746 | 0.07694 | (0.02518) | 46.7178 |
| 71 | 0.04945 | 166.09% | 1.6609 | 33.71911 | 0.04926 | 1.6609 | 21.58746 | 0.07694 | (0.02768) | 45.0569 |
| 72 | 0.04915 | 166.09% | 1.6609 | 35.43198 | 0.04688 | 1.6609 | 21.58746 | 0.07694 | (0.03006) | 43.3960 |
| 73 | 0.04882 | 168.18% | 1.6818 | 37.23187 | 0.04517 | 1.6818 | 21.58746 | 0.07791 | (0.03274) | 41.7142 |
| 74 | 0.04847 | 168.19% | 1.6819 | 39.12319 | 0.04299 | 1.6819 | 21.58746 | 0.07791 | (0.03492) | 40.0323 |
| 75 | 0.04810 | 168.18% | 1.6818 | 41.11058 | 0.04091 | 1.6818 | 21.58746 | 0.07791 | (0.03700) | 38.3505 |
| 76 | 0.04772 | 167.10% | 1.6710 | 43.19893 | 0.03868 | 1.6710 | 21.58746 | 0.07741 | (0.03872) | 36.6795 |
| 77 | 0.04731 | 166.74% | 1.6674 | 45.39336 | 0.03673 | 1.6674 | 21.58746 | 0.07724 | (0.04051) | 35.0121 |
| 78 | 0.04689 | 166.74% | 1.6674 | 47.69927 | 0.03496 | 1.6674 | 21.58746 | 0.07724 | (0.04228) | 33.3447 |
| 79 | 0.04646 | 164.06% | 1.6406 | 50.12231 | 0.03273 | 1.6406 | 21.58746 | 0.07600 | (0.04327) | 31.7041 |
| 80 | 0.04601 | 161.39% | 1.6139 | 52.66844 | 0.03064 | 1.6139 | 21.58746 | 0.07476 | (0.04412) | 30.0902 |
| 81 | 0.04556 | 161.38% | 1.6138 | 55.34391 | 0.02916 | 1.6138 | 21.58746 | 0.07476 | (0.04560) | 28.4764 |
| 82 | 0.04510 | 159.09% | 1.5909 | 58.15529 | 0.02736 | 1.5909 | 21.58746 | 0.07370 | (0.04634) | 26.8855 |
| 83 | 0.04464 | 152.22% | 1.5222 | 61.10949 | 0.02491 | 1.5222 | 21.58746 | 0.07051 | (0.04560) | 25.3633 |
| 84 | 0.04417 | 152.21% | 1.5221 | 64.21375 | 0.02370 | 1.5221 | 21.58746 | 0.07051 | (0.04680) | 23.8412 |
| 85 | 0.04369 | 152.22% | 1.5222 | 67.47570 | 0.02256 | 1.5222 | 21.58746 | 0.07051 | (0.04795) | 22.3190 |
| 86 | 0.04324 | 139.60% | 1.3960 | 70.90335 | 0.01969 | 1.3960 | 21.58746 | 0.06467 | (0.04498) | 20.9230 |
| 87 | 0.04278 | 139.60% | 1.3960 | 74.50513 | 0.01874 | 1.3960 | 21.58746 | 0.06467 | (0.04593) | 19.5270 |
| 88 | 0.04231 | 139.60% | 1.3960 | 78.28986 | 0.01783 | 1.3960 | 21.58746 | 0.06467 | (0.04684) | 18.1310 |
| 89 | 0.04188 | 128.13% | 1.2813 | 82.26686 | 0.01557 | 1.2813 | 21.58746 | 0.05935 | (0.04378) | 16.8497 |
| 90 | 0.04144 | 124.31% | 1.2431 | 86.44588 | 0.01438 | 1.2431 | 21.58746 | 0.05758 | (0.04320) | 15.6066 |
| 91 | 0.04101 | 124.31% | 1.2431 | 90.83719 | 0.01368 | 1.2431 | 21.58746 | 0.05758 | (0.04390) | 14.3635 |
| 92 | 0.04059 | 115.84% | 1.1584 | 95.45157 | 0.01214 | 1.1584 | 21.58746 | 0.05366 | (0.04152) | 13.2051 |
| 93 | 0.04020 | 107.39% | 1.0739 | 100.30035 | 0.01071 | 1.0739 | 21.58746 | 0.04975 | (0.03904) | 12.1312 |
| 94 | 0.03980 | 107.38% | 1.0738 | 105.39544 | 0.01019 | 1.0738 | 21.58746 | 0.04974 | (0.03955) | 11.0574 |
| 95 | 0.03942 | 103.02% | 1.0302 | 110.74936 | 0.00930 | 1.0302 | 21.58746 | 0.04772 | (0.03842) | 10.0272 |
| 96 | 0.03908 | 89.94% | 0.8994 | 116.37524 | 0.00773 | 0.8994 | 21.58746 | 0.04166 | (0.03393) | 9.1278 |
| 97 | 0.03874 | 89.94% | 0.8994 | 122.28691 | 0.00735 | 0.8994 | 21.58746 | 0.04166 | (0.03431) | 8.2284 |
| 98 | 0.03839 | 89.94% | 0.8994 | 128.49888 | 0.00700 | 0.8994 | 21.58746 | 0.04166 | (0.03466) | 7.3290 |
| 99 | 0.03811 | 72.86% | 0.7286 | 135.02641 | 0.00540 | 0.7286 | 21.58746 | 0.03375 | (0.02836) | 6.6004 |
| 100 | 0.03782 | 72.86% | 0.7286 | 141.88553 | 0.00514 | 0.7286 | 21.58746 | 0.03375 | (0.02862) | 5.8718 |
| 101 | 0.03753 | 72.86% | 0.7286 | 149.09308 | 0.00489 | 0.7286 | 21.58746 | 0.03375 | (0.02886) | 5.1432 |
| 102 | 0.03729 | 60.84% | 0.6084 | 156.66677 | 0.00388 | 0.6084 | 21.58746 | 0.02818 | (0.02430) | 4.5348 |
| 103 | 0.03706 | 56.83% | 0.5683 | 164.62518 | 0.00345 | 0.5683 | 21.58746 | 0.02633 | (0.02287) | 3.9665 |
| 104 | 0.03683 | 56.83% | 0.5683 | 172.98787 | 0.00329 | 0.5683 | 21.58746 | 0.02633 | (0.02304) | 3.3982 |
| 105 | 0.03663 | 49.42% | 0.4942 | 181.77536 | 0.00272 | 0.4942 | 21.58746 | 0.02289 | (0.02017) | 2.9040 |
| 106 | 0.03646 | 42.00% | 0.4200 | 191.00925 | 0.00220 | 0.4200 | 21.58746 | 0.01946 | (0.01726) | 2.4840 |
| 107 | 0.03628 | 42.00% | 0.4200 | 200.71221 | 0.00209 | 0.4200 | 21.58746 | 0.01946 | (0.01736) | 2.0640 |
| 108 | 0.03612 | 38.63% | 0.3863 | 210.90805 | 0.00183 | 0.3863 | 21.58746 | 0.01789 | (0.01606) | 1.6777 |
| 109 | 0.03600 | 28.52% | 0.2852 | 221.62183 | 0.00129 | 0.2852 | 21.58746 | 0.01321 | (0.01192) | 1.3925 |
| 110 | 0.03588 | 28.53% | 0.2853 | 232.87986 | 0.00123 | 0.2853 | 21.58746 | 0.01322 | (0.01199) | 1.1072 |
| 111 | 0.03576 | 28.52% | 0.2852 | 244.70977 | 0.00117 | 0.2852 | 21.58746 | 0.01321 | (0.01205) | 0.8220 |
| 112 | 0.03569 | 16.68% | 0.1668 | 257.14062 | 0.00065 | 0.1668 | 21.58746 | 0.00773 | (0.00708) | 0.6552 |
| 113 | 0.03562 | 16.67% | 0.1667 | 270.20294 | 0.00062 | 0.1667 | 21.58746 | 0.00772 | (0.00711) | 0.4885 |
| 114 | 0.03555 | 16.68% | 0.1668 | 283.92880 | 0.00059 | 0.1668 | 21.58746 | 0.00773 | (0.00714) | 0.3217 |
| 115 | 0.03551 | 9.57% | 0.0957 | 298.35192 | 0.00032 | 0.0957 | 21.58746 | 0.00443 | (0.00411) | 0.2260 |
| 116 | 0.03548 | 7.20% | 0.0720 | 313.50770 | 0.00023 | 0.0720 | 21.58746 | 0.00334 | (0.00311) | 0.1540 |
| | | 99.8460 | 99.8460 | | | | | | | |

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor

Iowa Curve R 2 & 54 Year Average Life

Real Cost of Capital = 5.08%

| YEAR | (A) PVCD | (B) % RENEWED | (C) NUM1 | (D) DEM1 | (E) NUM1/DEM1 | (F) NUM2 | (G) DEM2 | (H) NUM2/DEM2 | (I) INSTANCE | (J) Iowa R 2.0 |
|---|---|---|---|---|---|---|---|---|---|---|
| | ((A){yr-1} +(I)) / 100 | ((J,{yr-1})-(J)) * 100 | (B) | 1.0508 ^Year | (C) / (D) | (B) | 1.0508 ^52 | (F) / (G) | (E) - (H) | (Given) |
| | | | | | | | | | | 100.0000 |
| 1 | 0.00082 | 9.41% | 0.0941 | 1.05080 | 0.08953 | 0.0941 | 13.15249 | 0.00715 | 0.08237 | 99.9059 |
| 2 | 0.00238 | 18.81% | 0.1881 | 1.10418 | 0.17040 | 0.1881 | 13.15249 | 0.01431 | 0.15609 | 99.7178 |
| 3 | 0.00386 | 18.81% | 0.1881 | 1.16027 | 0.16216 | 0.1881 | 13.15249 | 0.01431 | 0.14785 | 99.5296 |
| 4 | 0.00546 | 21.48% | 0.2148 | 1.21921 | 0.17619 | 0.2148 | 13.15249 | 0.01633 | 0.15986 | 99.3148 |
| 5 | 0.00702 | 22.15% | 0.2215 | 1.28114 | 0.17288 | 0.2215 | 13.15249 | 0.01684 | 0.15604 | 99.0933 |
| 6 | 0.00852 | 22.53% | 0.2253 | 1.34622 | 0.16738 | 0.2253 | 13.15249 | 0.01713 | 0.15025 | 98.8680 |
| 7 | 0.01016 | 26.00% | 0.2600 | 1.41461 | 0.18380 | 0.2600 | 13.15249 | 0.01977 | 0.16403 | 98.6080 |
| 8 | 0.01172 | 26.00% | 0.2600 | 1.48647 | 0.17491 | 0.2600 | 13.15249 | 0.01977 | 0.15514 | 98.3480 |
| 9 | 0.01328 | 27.72% | 0.2772 | 1.56198 | 0.17746 | 0.2772 | 13.15249 | 0.02107 | 0.15638 | 98.0708 |
| 10 | 0.01490 | 30.30% | 0.3030 | 1.64132 | 0.18458 | 0.3030 | 13.15249 | 0.02303 | 0.16155 | 97.7679 |
| 11 | 0.01642 | 30.30% | 0.3030 | 1.72470 | 0.17566 | 0.3030 | 13.15249 | 0.02303 | 0.15263 | 97.4649 |
| 12 | 0.01802 | 33.69% | 0.3369 | 1.81231 | 0.18591 | 0.3369 | 13.15249 | 0.02562 | 0.16029 | 97.1280 |
| 13 | 0.01960 | 35.15% | 0.3515 | 1.90437 | 0.18457 | 0.3515 | 13.15249 | 0.02672 | 0.15784 | 96.7765 |
| 14 | 0.02109 | 35.15% | 0.3515 | 2.00111 | 0.17564 | 0.3515 | 13.15249 | 0.02672 | 0.14892 | 96.4250 |
| 15 | 0.02271 | 40.59% | 0.4059 | 2.10276 | 0.19304 | 0.4059 | 13.15249 | 0.03086 | 0.16218 | 96.0191 |
| 16 | 0.02424 | 40.59% | 0.4059 | 2.20958 | 0.18371 | 0.4059 | 13.15249 | 0.03086 | 0.15285 | 95.6131 |
| 17 | 0.02575 | 42.39% | 0.4239 | 2.32182 | 0.18258 | 0.4239 | 13.15249 | 0.03223 | 0.15035 | 95.1892 |
| 18 | 0.02730 | 46.59% | 0.4659 | 2.43977 | 0.19097 | 0.4659 | 13.15249 | 0.03542 | 0.15555 | 94.7233 |
| 19 | 0.02876 | 46.59% | 0.4659 | 2.56371 | 0.18174 | 0.4659 | 13.15249 | 0.03542 | 0.14631 | 94.2574 |
| 20 | 0.03026 | 50.64% | 0.5064 | 2.69394 | 0.18797 | 0.5064 | 13.15249 | 0.03850 | 0.14947 | 93.7510 |
| 21 | 0.03174 | 53.33% | 0.5333 | 2.83079 | 0.18840 | 0.5333 | 13.15249 | 0.04055 | 0.14785 | 93.2177 |
| 22 | 0.03313 | 53.33% | 0.5333 | 2.97459 | 0.17930 | 0.5333 | 13.15249 | 0.04055 | 0.13875 | 92.6843 |
| 23 | 0.03459 | 60.03% | 0.6003 | 3.12569 | 0.19206 | 0.6003 | 13.15249 | 0.04564 | 0.14642 | 92.0840 |
| 24 | 0.03598 | 60.78% | 0.6078 | 3.28447 | 0.18505 | 0.6078 | 13.15249 | 0.04621 | 0.13884 | 91.4762 |
| 25 | 0.03731 | 62.42% | 0.6242 | 3.45131 | 0.18087 | 0.6242 | 13.15249 | 0.04746 | 0.13340 | 90.8520 |
| 26 | 0.03869 | 69.00% | 0.6900 | 3.62664 | 0.19026 | 0.6900 | 13.15249 | 0.05246 | 0.13780 | 90.1620 |
| 27 | 0.03998 | 69.00% | 0.6900 | 3.81086 | 0.18106 | 0.6900 | 13.15249 | 0.05246 | 0.12860 | 89.4720 |
| 28 | 0.04125 | 73.52% | 0.7352 | 4.00445 | 0.18359 | 0.7352 | 13.15249 | 0.05590 | 0.12770 | 88.7368 |
| 29 | 0.04251 | 78.04% | 0.7804 | 4.20787 | 0.18546 | 0.7804 | 13.15249 | 0.05933 | 0.12612 | 87.9564 |
| 30 | 0.04369 | 78.04% | 0.7804 | 4.42162 | 0.17649 | 0.7804 | 13.15249 | 0.05933 | 0.11716 | 87.1761 |
| 31 | 0.04488 | 85.92% | 0.8592 | 4.64623 | 0.18492 | 0.8592 | 13.15249 | 0.06532 | 0.11960 | 86.3169 |
| 32 | 0.04601 | 87.89% | 0.8789 | 4.88225 | 0.18002 | 0.8789 | 13.15249 | 0.06682 | 0.11319 | 85.4380 |
| 33 | 0.04707 | 88.96% | 0.8896 | 5.13026 | 0.17340 | 0.8896 | 13.15249 | 0.06764 | 0.10576 | 84.5484 |
| 34 | 0.04815 | 98.59% | 0.9859 | 5.39087 | 0.18289 | 0.9859 | 13.15249 | 0.07496 | 0.10793 | 83.5625 |
| 35 | 0.04914 | 98.59% | 0.9859 | 5.66472 | 0.17405 | 0.9859 | 13.15249 | 0.07496 | 0.09909 | 82.5766 |
| 36 | 0.05009 | 103.21% | 1.0321 | 5.95248 | 0.17340 | 1.0321 | 13.15249 | 0.07848 | 0.09492 | 81.5444 |
| 37 | 0.05101 | 110.15% | 1.1015 | 6.25485 | 0.17610 | 1.1015 | 13.15249 | 0.08375 | 0.09235 | 80.4429 |
| 38 | 0.05185 | 110.15% | 1.1015 | 6.57259 | 0.16759 | 1.1015 | 13.15249 | 0.08375 | 0.08384 | 79.3414 |
| 39 | 0.05267 | 118.70% | 1.1870 | 6.90647 | 0.17187 | 1.1870 | 13.15249 | 0.09025 | 0.08162 | 78.1544 |
| 40 | 0.05342 | 122.37% | 1.2237 | 7.25730 | 0.16862 | 1.2237 | 13.15249 | 0.09304 | 0.07558 | 76.9307 |
| 41 | 0.05410 | 122.37% | 1.2237 | 7.62596 | 0.16047 | 1.2237 | 13.15249 | 0.09304 | 0.06743 | 75.7070 |
| 42 | 0.05476 | 135.19% | 1.3519 | 8.01335 | 0.16870 | 1.3519 | 13.15249 | 0.10278 | 0.06592 | 74.3551 |
| 43 | 0.05534 | 135.19% | 1.3519 | 8.42041 | 0.16054 | 1.3519 | 13.15249 | 0.10278 | 0.05776 | 73.0033 |
| 44 | 0.05585 | 139.11% | 1.3911 | 8.84816 | 0.15722 | 1.3911 | 13.15249 | 0.10577 | 0.05145 | 71.6122 |
| 45 | 0.05632 | 148.26% | 1.4826 | 9.29763 | 0.15946 | 1.4826 | 13.15249 | 0.11272 | 0.04674 | 70.1296 |
| 46 | 0.05671 | 148.26% | 1.4826 | 9.76993 | 0.15175 | 1.4826 | 13.15249 | 0.11272 | 0.03903 | 68.6470 |
| 47 | 0.05704 | 156.06% | 1.5606 | 10.26623 | 0.15201 | 1.5606 | 13.15249 | 0.11865 | 0.03336 | 67.0864 |
| 48 | 0.05731 | 161.26% | 1.6126 | 10.78774 | 0.14948 | 1.6126 | 13.15249 | 0.12261 | 0.02688 | 65.4739 |
| 49 | 0.05751 | 161.26% | 1.6126 | 11.33573 | 0.14226 | 1.6126 | 13.15249 | 0.12261 | 0.01965 | 63.8613 |
| 50 | 0.05764 | 172.39% | 1.7239 | 11.91157 | 0.14473 | 1.7239 | 13.15249 | 0.13107 | 0.01365 | 62.1373 |
| 51 | 0.05771 | 173.63% | 1.7363 | 12.51666 | 0.13872 | 1.7363 | 13.15249 | 0.13201 | 0.00671 | 60.4010 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 52 | 0.05771 | 175.84% | 1.7584 | 13.15249 | 0.13370 | 1.7584 | 13.15249 | 0.13370 | - | 58.6426 |
| 53 | 0.05764 | 184.70% | 1.8470 | 13.82061 | 0.13364 | 1.8470 | 13.15249 | 0.14043 | (0.00679) | 56.7956 |
| 54 | 0.05751 | 184.70% | 1.8470 | 14.52267 | 0.12718 | 1.8470 | 13.15249 | 0.14043 | (0.01325) | 54.9485 |
| 55 | 0.05731 | 189.22% | 1.8922 | 15.26040 | 0.12400 | 1.8922 | 13.15249 | 0.14387 | (0.01987) | 53.0563 |
| 56 | 0.05705 | 193.74% | 1.9374 | 16.03560 | 0.12082 | 1.9374 | 13.15249 | 0.14730 | (0.02648) | 51.1189 |
| 57 | 0.05672 | 193.74% | 1.9374 | 16.85019 | 0.11498 | 1.9374 | 13.15249 | 0.14730 | (0.03233) | 49.1815 |
| 58 | 0.05633 | 198.69% | 1.9869 | 17.70615 | 0.11221 | 1.9869 | 13.15249 | 0.15107 | (0.03885) | 47.1946 |
| 59 | 0.05589 | 199.93% | 1.9993 | 18.60559 | 0.10745 | 1.9993 | 13.15249 | 0.15201 | (0.04455) | 45.1953 |
| 60 | 0.05539 | 200.18% | 2.0018 | 19.55073 | 0.10239 | 2.0018 | 13.15249 | 0.15220 | (0.04981) | 43.1936 |
| 61 | 0.05484 | 202.44% | 2.0244 | 20.54387 | 0.09854 | 2.0244 | 13.15249 | 0.15392 | (0.05538) | 41.1691 |
| 62 | 0.05424 | 202.44% | 2.0244 | 21.58746 | 0.09378 | 2.0244 | 13.15249 | 0.15392 | (0.06014) | 39.1447 |
| 63 | 0.05359 | 201.75% | 2.0175 | 22.68407 | 0.08894 | 2.0175 | 13.15249 | 0.15339 | (0.06445) | 37.1272 |
| 64 | 0.05291 | 200.70% | 2.0070 | 23.83639 | 0.08420 | 2.0070 | 13.15249 | 0.15260 | (0.06840) | 35.1201 |
| 65 | 0.05218 | 200.70% | 2.0070 | 25.04723 | 0.08013 | 2.0070 | 13.15249 | 0.15260 | (0.07247) | 33.1131 |
| 66 | 0.05144 | 196.19% | 1.9619 | 26.31959 | 0.07454 | 1.9619 | 13.15249 | 0.14917 | (0.07463) | 31.1512 |
| 67 | 0.05066 | 194.26% | 1.9426 | 27.65658 | 0.07024 | 1.9426 | 13.15249 | 0.14770 | (0.07746) | 29.2086 |
| 68 | 0.04985 | 194.26% | 1.9426 | 29.06149 | 0.06684 | 1.9426 | 13.15249 | 0.14770 | (0.08085) | 27.2660 |
| 69 | 0.04906 | 183.22% | 1.8322 | 30.53777 | 0.06000 | 1.8322 | 13.15249 | 0.13931 | (0.07931) | 25.4338 |
| 70 | 0.04824 | 183.22% | 1.8322 | 32.08904 | 0.05710 | 1.8322 | 13.15249 | 0.13931 | (0.08221) | 23.6016 |
| 71 | 0.04741 | 178.67% | 1.7867 | 33.71911 | 0.05299 | 1.7867 | 13.15249 | 0.13584 | (0.08286) | 21.8149 |
| 72 | 0.04661 | 168.04% | 1.6804 | 35.43198 | 0.04743 | 1.6804 | 13.15249 | 0.12776 | (0.08034) | 20.1345 |
| 73 | 0.04578 | 168.04% | 1.6804 | 37.23187 | 0.04513 | 1.6804 | 13.15249 | 0.12776 | (0.08263) | 18.4541 |
| 74 | 0.04499 | 156.99% | 1.5699 | 39.12319 | 0.04013 | 1.5699 | 13.15249 | 0.11936 | (0.07924) | 16.8842 |
| 75 | 0.04421 | 149.63% | 1.4963 | 41.11058 | 0.03640 | 1.4963 | 13.15249 | 0.11377 | (0.07737) | 15.3879 |
| 76 | 0.04342 | 149.63% | 1.4963 | 43.19893 | 0.03464 | 1.4963 | 13.15249 | 0.11377 | (0.07913) | 13.8916 |
| 77 | 0.04271 | 131.30% | 1.3130 | 45.39336 | 0.02892 | 1.3130 | 13.15249 | 0.09983 | (0.07090) | 12.5787 |
| 78 | 0.04200 | 129.26% | 1.2926 | 47.69927 | 0.02710 | 1.2926 | 13.15249 | 0.09828 | (0.07118) | 11.2861 |
| 79 | 0.04130 | 125.06% | 1.2506 | 50.12231 | 0.02495 | 1.2506 | 13.15249 | 0.09508 | (0.07013) | 10.0355 |
| 80 | 0.04068 | 108.26% | 1.0826 | 52.66844 | 0.02055 | 1.0826 | 13.15249 | 0.08231 | (0.06176) | 8.9529 |
| 81 | 0.04006 | 108.26% | 1.0826 | 55.34391 | 0.01956 | 1.0826 | 13.15249 | 0.08231 | (0.06275) | 7.8703 |
| 82 | 0.03948 | 97.98% | 0.9798 | 58.15529 | 0.01685 | 0.9798 | 13.15249 | 0.07450 | (0.05765) | 6.8905 |
| 83 | 0.03896 | 87.70% | 0.8770 | 61.10949 | 0.01435 | 0.8770 | 13.15249 | 0.06668 | (0.05233) | 6.0134 |
| 84 | 0.03843 | 87.70% | 0.8770 | 64.21375 | 0.01366 | 0.8770 | 13.15249 | 0.06668 | (0.05302) | 5.1364 |
| 85 | 0.03798 | 72.27% | 0.7227 | 67.47570 | 0.01071 | 0.7227 | 13.15249 | 0.05495 | (0.04424) | 4.4137 |
| 86 | 0.03756 | 68.41% | 0.6841 | 70.90335 | 0.00965 | 0.6841 | 13.15249 | 0.05201 | (0.04236) | 3.7297 |
| 87 | 0.03714 | 66.62% | 0.6662 | 74.50513 | 0.00894 | 0.6662 | 13.15249 | 0.05065 | (0.04171) | 3.0634 |
| 88 | 0.03682 | 50.56% | 0.5056 | 78.28986 | 0.00646 | 0.5056 | 13.15249 | 0.03844 | (0.03198) | 2.5579 |
| 89 | 0.03650 | 50.56% | 0.5056 | 82.26686 | 0.00615 | 0.5056 | 13.15249 | 0.03844 | (0.03229) | 2.0523 |
| 90 | 0.03622 | 44.07% | 0.4407 | 86.44588 | 0.00510 | 0.4407 | 13.15249 | 0.03350 | (0.02841) | 1.6117 |
| 91 | 0.03599 | 34.33% | 0.3433 | 90.83719 | 0.00378 | 0.3433 | 13.15249 | 0.02610 | (0.02232) | 1.2683 |
| 92 | 0.03577 | 34.33% | 0.3433 | 95.45157 | 0.00360 | 0.3433 | 13.15249 | 0.02610 | (0.02251) | 0.9250 |
| 93 | 0.03561 | 24.35% | 0.2435 | 100.30035 | 0.00243 | 0.2435 | 13.15249 | 0.01852 | (0.01609) | 0.6815 |
| 94 | 0.03547 | 20.07% | 0.2007 | 105.39544 | 0.00190 | 0.2007 | 13.15249 | 0.01526 | (0.01336) | 0.4807 |
| 95 | 0.03534 | 20.07% | 0.2007 | 110.74936 | 0.00181 | 0.2007 | 13.15249 | 0.01526 | (0.01345) | 0.2800 |
| 96 | 0.03528 | 8.67% | 0.0867 | 116.37524 | 0.00074 | 0.0867 | 13.15249 | 0.00659 | (0.00584) | 0.1933 |
| 97 | 0.03522 | 8.67% | 0.0867 | 122.28691 | 0.00071 | 0.0867 | 13.15249 | 0.00659 | (0.00588) | 0.1067 |
| | | | 99.8933 | 54.8956 | | | | | | |

Depreciation

PACIFICORP
Remaining Life Depreciation Rates

| [1] Account Number | [2] Description | [3] 6/30/2023 Balance | [4] IOWA CURVE | [5] Average Life | [6] NET SALVAGE Percent | [7] NET SALVAGE Amount | |
|---|---|---|---|---|---|---|---|
| | | $ | | Yrs | % | $ | |
| | TRANSMISSION PLANT | | | | | | |
| 350.20 | Land Rights | 282,573,177 | R4 | 90.00 | 0.00% | - | |
| 352.00 | Structures & Improvements | 386,384,736 | R2.5 | 75.00 | -5.00% | (19,319,237) | |
| 353.00 | Station Equipment | 2,727,416,573 | S0 | 60.00 | -10.00% | (272,741,657) | |
| 353.70 | Supervisory Equipment | - | | | | - | |
| 354.00 | Towers & Fixtures | 1,526,005,036 | R4 | 72.00 | -8.00% | (122,080,403) | |
| 355.00 | Poles & Fixtures | 1,278,838,555 | R2.5 | 62.00 | -40.00% | (511,535,422) | |
| 356.00 | OH Conductors & Devices | 1,676,119,586 | R2.5 | 68.00 | -30.00% | (502,835,876) | |
| 356.20 | Clearing | - | | | | - | |
| 357.00 | UG Conduit | 3,872,987 | S2.5 | 60.00 | 0.00% | - | |
| 358.00 | UG Conductors & Devices | 9,080,617 | S2.5 | 60.00 | -5.00% | (454,031) | |
| 359.00 | Roads & Trails | 12,141,468 | R5 | 75.00 | 0.00% | - | |
| | Total Transmission Plant | 7,902,432,736 | | 65.40 | -18.08% | (1,428,966,626) | |
| | | | | **Use 65 Years** | | | 65 |
| | TRANSMISSION PLANT excludes land accounts | | | | | | |
| 352.00 | Structures & Improvements | 386,384,736 | 2.50 | 5.07% | 0.13 | | |
| 353.00 | Station Equipment | 2,727,416,573 | - | 35.79% | - | | |
| 353.70 | Supervisory Equipment | - | | 0.00% | - | | |
| 354.00 | Towers & Fixtures | 1,526,005,036 | 4.00 | 20.03% | 0.80 | | |
| 355.00 | Poles & Fixtures | 1,278,838,555 | 2.50 | 16.78% | 0.42 | | |
| 356.00 | OH Conductors & Devices | 1,676,119,586 | 2.50 | 22.00% | 0.55 | | |
| 356.20 | Clearing | - | - | 0.00% | - | | |
| 357.00 | UG Conduit | 3,872,987 | 2.50 | 0.05% | 0.00 | | |
| 358.00 | UG Conductors & Devices | 9,080,617 | 2.50 | 0.12% | 0.00 | | |
| 359.00 | Roads & Trails | 12,141,468 | 5.00 | 0.16% | 0.01 | | |
| | Total Transmission Plant | 7,619,859,559 | | 100.00% | 1.91 | **Use R 2** | |

| [1] Account Number | [2] Description | [3] 6/30/2021 Balance | [4] IOWA CURVE | [5] Average Life | [6] NET SALVAGE Percent | [7] NET SALVAGE Amount |
|---|---|---|---|---|---|---|
| | | $ | | Yrs | % | $ |
| | DISTRIBUTION PLANT (OREGON) | | | | | |
| 360.20 | Land Rights | 6,441,896 | S1.5 | 70.00 | 0.00% | - |
| 361.00 | Structures & Improvements | 35,033,648 | R2 | 67.00 | -10.00% | (3,503,365) |
| 362.00 | Station Equipment | 306,033,063 | R1 | 53.00 | -20.00% | (61,206,613) |
| 362.70 | Supervisory & Alarm Equipment | | | | | - |
| 364.00 | Poles, Towers & Fixtures | 516,891,491 | R1 | 58.00 | -100.00% | (516,891,491) |
| 365.00 | OH Conductors & Devices | 325,012,527 | R1 | 65.00 | -50.00% | (162,506,263) |
| 366.00 | UG Conduit | 120,810,576 | R3 | 75.00 | -45.00% | (54,364,759) |
| 367.00 | UG Conductors & Devices | 235,065,979 | R2.5 | 60.00 | -35.00% | (82,273,093) |
| 368.00 | Line Transformers | 532,450,677 | R1.5 | 46.00 | -25.00% | (133,112,669) |
| 369.10 | Overhead Services | 117,296,138 | R2 | 60.00 | -35.00% | (41,053,648) |
| 369.20 | Underground Services | 242,221,216 | R4 | 60.00 | -40.00% | (96,888,486) |
| 370.00 | Meters | 105,898,473 | S3 | 20.00 | -3.00% | (3,176,954) |
| 371.00 | I.O.C.P. | 2,685,798 | L0 | 27.00 | -50.00% | (1,342,899) |
| 373.00 | Street Lighting & Signal Systems | 25,130,359 | R1 | 45.00 | -30.00% | (7,539,108) |
| | Total OREGON Distribution Plant | 2,570,971,841 | | 53.60 | -45.27% | (1,163,859,348) |
| | | | | **Use 54 years** | | |

54

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | DISTRIBUTION PLANT excludes land accounts (OREGON) | | | | | | |
| 361.00 | Structures & Improvements | 35,033,648 | 2.00 | 1.37% | 0.03 | | Curves: |
| 362.00 | Station Equipment | 306,033,063 | 1.00 | 11.93% | 0.12 | | R=positive |
| 362.70 | Supervisory & Alarm Equipment | - | | 0.00% | - | | L=negative |
| 364.00 | Poles, Towers & Fixtures | 516,891,491 | 1.00 | 20.16% | 0.20 | | S=0 |
| 365.00 | OH Conductors & Devices | 325,012,527 | 1.00 | 12.67% | 0.13 | | |
| 366.00 | UG Conduit | 120,810,576 | 3.00 | 4.71% | 0.14 | | R means right of the standard |
| 367.00 | UG Conductors & Devices | 235,065,979 | 2.50 | 9.17% | 0.23 | | L means left of the standard |
| 368.00 | Line Transformers | 532,450,677 | 1.50 | 20.76% | 0.31 | | S is at the standard |
| 369.10 | Overhead Services | 117,296,138 | 2.00 | 4.57% | 0.09 | | |
| 369.20 | Underground Services | 242,221,216 | 4.00 | 9.45% | 0.38 | | |
| 370.00 | Meters | 105,898,473 | 3.00 | 4.13% | 0.12 | | |
| 371.00 | I.O.C.P. | 2,685,798 | - | 0.10% | - | | |
| 373.00 | Street Lighting & Signal Systems | 25,130,359 | 1.00 | 0.98% | 0.01 | | |
| | Total OREGON Distribution Plant | 2,564,529,945 | | 100.00% | 1.76 | **Use R 2** | |

Cust

PacifiCorp
Oregon Marginal Cost Study
Customers and MWh @ Sales

| | | | 12 Months Ended June 30, 2023 - Actual | | | | | | | | | 12 Months Ended December 2025 - Normalized | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | | | | (H) | (I) |
| Line | Description | Del. Volt | Average Customers | % Total Class | Annual MWh's | % Total Class | Average Billing kW | % Total Class | Three Phase Customers | Three Phase % of Customers | Single Phase % of Customers | Average Customers | Annual MWh's |
| 1 | Res - Schedule 4 | (sec) | 533,013 | 100.00% | 5,814,272 | 100.00% | 5,042,753 | 100.00% | - | 0.00% | 100.00% | 513,581 | 5,787,620 |
| 2 | | | | | | | | | | | | | |
| 3 | GS - Schedule 23 | | | | | | | | | | | | |
| 4 | 0-15 kW | (sec) | 71,109 | 82.43% | 586,948 | 47.87% | 947,994 | 63.89% | 13,677 | 19.23% | 80.77% | 70,880 | 555,432 |
| 5 | 15+ kW | (sec) | 15,152 | 17.57% | 639,141 | 52.13% | 535,908 | 36.11% | 6,937 | 45.78% | 54.22% | 15,103 | 604,823 |
| 6 | Sec Subtotal | | 86,261 | 100.00% | 1,226,089 | 100.00% | 1,483,903 | 100.00% | 20,614 | 23.90% | 76.10% | 85,983 | 1,160,255 |
| 7 | Primary | (pri) | 50 | | 1,955 | | 11,400 | | 50 | 99.38% | 0.62% | 50 | 1,877 |
| 8 | Total | | 86,312 | | 1,228,044 | | 1,495,302 | | 20,664 | 23.94% | 76.06% | 86,033 | 1,162,132 |
| 9 | | | | | | | | | | | | | |
| 10 | GS - Schedule 28 | | | | | | | | | | | | |
| 11 | 0-50 kW | (sec) | 4,543 | 43.68% | 434,116 | 20.82% | 191,574 | 17.93% | 3,213 | 70.73% | 29.27% | 4,630 | 425,310 |
| 12 | 51-100 kW | (sec) | 3,614 | 34.75% | 669,847 | 32.12% | 390,191 | 36.52% | 3,086 | 85.40% | 14.60% | 3,683 | 656,260 |
| 13 | 100 + kW | (sec) | 2,243 | 21.57% | 981,603 | 47.07% | 486,664 | 45.55% | 2,187 | 97.52% | 2.48% | 2,286 | 961,692 |
| 14 | Sec Subtotal | | 10,399 | 100.00% | 2,085,566 | 100.00% | 1,068,429 | 100.00% | 8,486 | 81.60% | 18.40% | 10,599 | 2,043,261 |
| 15 | Primary | (pri) | 59 | | 21,809 | | 39,149 | | 59 | 100.79% | -0.79% | 59 | 21,451 |
| 16 | Total | | 10,458 | | 2,107,374 | | 1,107,578 | | 8,545 | 81.71% | 18.29% | 10,658 | 2,064,712 |
| 17 | | | | | | | | | | | | | |
| 18 | GS - Schedule 30 | | | | | | | | | | | | |
| 19 | 0-300 kW | (sec) | 198 | 24.84% | 170,220 | 13.63% | 55,540 | 14.73% | 198 | 99.58% | 0.42% | 200 | 170,668 |
| 20 | 300+ kW | (sec) | 600 | 75.16% | 1,078,967 | 86.37% | 321,463 | 85.27% | 600 | 99.94% | 0.06% | 606 | 1,081,806 |
| 21 | Sec Subtotal | | 799 | 100.00% | 1,249,187 | 100.00% | 377,003 | 100.00% | 798 | 99.85% | 0.15% | 806 | 1,252,474 |
| 22 | Primary | (pri) | 40 | | 76,532 | | 53,025 | | 40 | 98.94% | 1.06% | 41 | 77,805 |
| 23 | Total | | 839 | | 1,325,719 | | 430,028 | | 838 | 99.81% | 0.19% | 847 | 1,330,279 |
| 24 | | | | | | | | | | | | | |
| 25 | LPS - Schedule 48 | | | | | | | | | | | | |
| 26 | 1 - 4 MW | (sec) | 81 | 95.25% | 456,583 | 79.89% | 105,438 | 80.15% | 81 | 100.60% | -0.60% | 82 | 456,088 |
| 27 | > 4 MW | (sec) | 4 | 4.75% | 114,945 | 20.11% | 26,117 | 19.85% | 4 | 99.59% | 0.41% | 4 | 114,820 |
| 28 | Sec Subtotal | | 85 | 100.00% | 571,528 | 100.00% | 131,555 | 100.00% | 85 | 100.56% | -0.56% | 86 | 570,908 |
| 29 | 1 - 4 MW | (pri) | 58 | 70.69% | 509,238 | 37.74% | 114,319 | 42.43% | 58 | 99.85% | 0.15% | 59 | 819,472 |
| 30 | > 4 MW | (pri) | 24 | 29.31% | 840,070 | 62.26% | 155,107 | 57.57% | 24 | 99.63% | 0.37% | 25 | 1,351,851 |
| 31 | Pri Subtotal | | 82 | 100.00% | 1,349,307 | 100.00% | 269,427 | 100.00% | 82 | 99.78% | 0.22% | 84 | 2,171,323 |
| 32 | Trans | (trn) | 7 | | 1,156,897 | | 317,201 | | 7 | 101.08% | -1.08% | 8 | 1,934,880 |
| 33 | Total | | 174 | | 3,077,732 | | 718,183 | | 174 | 100.21% | -0.21% | 178 | 4,677,111 |
| 34 | | | | | | | | | | | | | |
| 35 | Irrigation - Schedule 41 (Average) | (sec) | 3,353 | 100.00% | 196,326 | 100.00% | 186,770 | 100.00% | | 0.00% | 100.00% | 3,311 | 234,910 |
| 36 | | | | | | | | | | | | | |
| 37 | Irrigation - Schedule 41 (Annual) | (sec) | 6,149 | | | | | | 5,184 | 84.30% | 15.70% | 7,887 | 234,910 |
| 38 | | | | | | | | | | | | | |
| 39 | PS&H - Schedule 15 | (sec) | 5,991 | 79.08% | 2,159 | 10.47% | - | 0.00% | - | | | 5,833 | 2,128 |
| 40 | PS&H - Schedule 51 | (sec) | 1,194 | 15.76% | 8,930 | 43.32% | - | 0.00% | - | | | 1,210 | 7,898 |
| 41 | PS&H - Schedule 53 | (sec) | 294 | 3.88% | 8,075 | 39.17% | 2,050 | 23.08% | - | | | 296 | 8,821 |
| 42 | PS&H - Schedule 54 | (sec) | 98 | 1.29% | 1,450 | 7.03% | 6,832 | 76.92% | - | | | 98 | 1,374 |
| 43 | Total | | 7,577 | 100.00% | 20,614 | 100.00% | 8,881 | 100.00% | | | | 7,437 | 20,221 |

MW

PacifiCorp
Oregon Marginal Cost Study
Cutomer Loads at Sales - MW
12 Months Ended December 2025

| Line | Description | Del. Volt | (A) System Peak | (B) Distribution Peak | (C) Non-Coincident Peak | (D) Cust per Transformer | (E) Coincidence Factor for Winter Loads | (F) Weighted Transformer Peak |
|---|---|---|---|---|---|---|---|---|
| 1 | Res - Schedule 4 | (sec) | 1,021 | 1,213 | 5,043 | 4 | 0.67 | 3,379 |
| 2 | | | | | | | | |
| 3 | GS - Schedule 23 | | | | | | | |
| 4 | 0-15 kW | (sec) | 85 | 90 | 948 | 2 | 0.77 | 730 |
| 5 | 15+ kW | (sec) | 91 | 98 | 536 | 2 | 0.77 | 413 |
| 6 | Primary | (pri) | 0 | 0 | 11 | 1 | 1.00 | 11 |
| 7 | | | | | | | | |
| 8 | GS - Schedule 28 | | | | | | | |
| 9 | 0-50 kW | (sec) | 65 | 70 | 192 | 1 | 1.00 | 192 |
| 10 | 51-100 kW | (sec) | 99 | 104 | 390 | 1 | 1.00 | 390 |
| 11 | 100 + kW | (sec) | 141 | 147 | 487 | 1 | 1.00 | 487 |
| 12 | Primary | (pri) | 3 | 3 | 39 | 1 | 1.00 | 39 |
| 13 | | | | | | | | |
| 14 | GS - Schedule 30 | | | | | | | |
| 15 | 0-300 kW | (sec) | 25 | 26 | 56 | 2 | 0.77 | 43 |
| 16 | 300+ kW | (sec) | 153 | 158 | 321 | 2 | 0.77 | 248 |
| 17 | Primary | (pri) | 11 | 11 | 53 | 1 | 1.00 | 53 |
| 18 | | | | | | | | |
| 19 | LPS - Schedule 48 | | | | | | | |
| 20 | 1 - 4 MW | (sec) | 63 | 64 | 105 | 1 | 1.00 | 105 |
| 21 | 1 - 4 MW | (pri) | 70 | 72 | 114 | 1 | 1.00 | 114 |
| 22 | > 4 MW | (sec) | 14 | 14 | 26 | 1 | 1.00 | 26 |
| 23 | > 4 MW | (pri) | 204 | 208 | 155 | 1 | 1.00 | 155 |
| 24 | Trans | (trn) | 222 | 228 | 317 | 1 | 1.00 | 317 |
| 25 | | | | | | | | |
| 26 | Irrigation - Sch 41 | (sec) | 31 | 47 | 187 | 1 | 1.00 | 187 |
| 27 | | | | | | | | |
| 28 | Sch 15 | (sec) | 0 | 0 | 0 | 1 | 1.00 | 0 |
| 29 | Sch 51 | (sec) | 0 | 0 | 2 | 1 | 1.00 | 2 |
| 30 | Customer-Owned Lighting - Sch 53 | (sec) | 0 | 0 | 2 | 1 | 1.00 | 2 |
| 31 | Rec Field Lighting - Sch 54 | (sec) | 0 | 0 | 7 | 1 | 1.00 | 7 |

DistPeak

PacifiCorp
Oregon Marginal Cost Study
Weighted Distribution Peaks
Tied to December 2023 Forecast

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Jul-22 29 17:00 | Aug-22 25 17:00 | Sep-22 1 17:00 | Oct-22 27 08:00 | Nov-22 17 09:00 | Dec-22 16 09:00 | Jan-23 30 08:00 | Feb-23 1 08:00 | Mar-23 16 07:00 | Apr-23 4 07:00 | May-23 17 18:00 | Jun-23 29 16:00 | Sum of 12 Wgt Dist peaks |
| | Del. Volt | | | | | | | | | | | | | |
| Res - Schedule 4 | (sec) | 289.4 | 176.0 | 15.2 | 2.3 | 16.1 | 91.4 | 151.5 | 133.6 | 26.3 | 16.2 | 12.4 | 282.5 | 1,213.0 |
| GS - Schedule 23 | | | | | | | | | | | | | | |
| 0-15 kW | (sec) | 20.7 | 13.9 | 1.3 | 0.2 | 1.2 | 6.7 | 9.4 | 9.3 | 2.0 | 1.2 | 0.9 | 23.6 | 90.4 |
| 15+ kW | (sec) | 23.1 | 15.0 | 1.3 | 0.3 | 1.5 | 8.3 | 10.4 | 10.1 | 2.2 | 1.3 | 1.0 | 23.1 | 97.6 |
| Primary | (pri) | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.3 |
| GS - Schedule 28 | | | | | | | | | | | | | | |
| 0-50 kW | (sec) | 16.7 | 10.6 | 1.0 | 0.2 | 1.0 | 4.9 | 7.2 | 7.1 | 1.5 | 0.9 | 0.7 | 17.8 | 69.6 |
| 51-100 kW | (sec) | 25.5 | 16.7 | 1.5 | 0.2 | 1.5 | 7.6 | 10.7 | 10.8 | 2.4 | 1.3 | 1.1 | 24.9 | 104.3 |
| 100+ kW | (sec) | 32.7 | 22.6 | 1.9 | 0.4 | 2.3 | 11.9 | 16.6 | 16.7 | 3.7 | 2.1 | 1.5 | 34.0 | 146.5 |
| Primary | (pri) | 0.7 | 0.5 | 0.0 | 0.0 | 0.1 | 0.3 | 0.4 | 0.3 | 0.1 | 0.1 | 0.0 | 0.7 | 3.1 |
| GS - Schedule 30 | | | | | | | | | | | | | | |
| 0-300 kW | (sec) | 5.6 | 4.1 | 0.3 | 0.1 | 0.4 | 2.0 | 2.9 | 2.9 | 0.7 | 0.4 | 0.3 | 6.4 | 26.1 |
| 300+ kW | (sec) | 33.2 | 24.4 | 2.1 | 0.5 | 2.8 | 13.1 | 17.5 | 17.6 | 4.3 | 2.5 | 1.6 | 38.1 | 157.8 |
| Primary | (pri) | 2.5 | 1.7 | 0.1 | 0.0 | 0.2 | 0.9 | 1.3 | 1.2 | 0.3 | 0.2 | 0.1 | 2.5 | 11.0 |
| LPS - Schedule 48 | | | | | | | | | | | | | | |
| 1 - 4 MW | (sec) | 14.3 | 10.2 | 0.9 | 0.2 | 1.2 | 5.9 | 6.5 | 7.4 | 1.8 | 1.1 | 0.6 | 13.4 | 63.7 |
| 1 - 4 MW | (pri) | 16.2 | 11.7 | 1.1 | 0.2 | 1.3 | 6.2 | 7.1 | 7.3 | 1.9 | 1.1 | 0.8 | 16.7 | 71.8 |
| > 4 MW | (sec) | 2.9 | 2.5 | 0.2 | 0.0 | 0.3 | 1.4 | 1.4 | 1.5 | 0.4 | 0.2 | 0.2 | 3.5 | 14.4 |
| > 4 MW | (pri) | 42.3 | 36.4 | 3.0 | 0.6 | 3.7 | 19.7 | 19.7 | 21.9 | 5.1 | 3.0 | 2.6 | 49.9 | 207.9 |
| Trans | (trn) | 49.9 | 38.2 | 3.3 | 0.7 | 3.9 | 19.0 | 21.9 | 26.3 | 5.7 | 3.3 | 2.5 | 53.3 | 227.9 |
| Irrigation - Sch 41 | (sec) | 15.9 | 10.4 | 0.8 | 0.0 | 0.0 | 0.1 | 0.2 | 0.2 | 0.1 | 0.3 | 0.6 | 18.2 | 47.0 |
| Customer-Owned Lighting - Sch 53 | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rec Field Lighting - Sch 54 | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 |

PacifiCorp
Oregon Marginal Cost Study
Distribution Peaks @ Sales - MW
Tied to December 2023 Forecast

| A | B | C | D | E | F | G | H | I | J | K | L | M | N |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Jul-22 29 17:00 | Aug-22 25 17:00 | Sep-22 1 17:00 | Oct-22 27 08:00 | Nov-22 17 09:00 | Dec-22 16 09:00 | Jan-23 30 08:00 | Feb-23 1 08:00 | Mar-23 16 07:00 | Apr-23 4 07:00 | May-23 17 18:00 | Jun-23 29 16:00 |
| | Del. Volt | | | | | | | | | | | | |
| Res - Schedule 4 | (sec) | 1,366.2 | 1,113.0 | 1,122.3 | 827.0 | 997.8 | 1,131.4 | 1,390.7 | 1,159.8 | 969.3 | 1,039.9 | 1,037.3 | 1,187.7 |
| GS - Schedule 23 | | | | | | | | | | | | | |
| 0-15 kW | (sec) | 97.8 | 88.2 | 92.4 | 70.3 | 74.8 | 82.3 | 86.1 | 81.0 | 73.6 | 73.9 | 78.2 | 99.2 |
| 15+ kW | (sec) | 109.1 | 95.1 | 94.0 | 99.3 | 90.7 | 103.3 | 95.3 | 87.6 | 81.4 | 83.3 | 84.8 | 97.1 |
| Primary | (pri) | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| GS - Schedule 28 | | | | | | | | | | | | | |
| 0-50 kW | (sec) | 79.0 | 66.9 | 72.1 | 55.4 | 59.1 | 60.8 | 66.2 | 61.4 | 56.7 | 55.1 | 60.5 | 75.0 |
| 51-100 kW | (sec) | 120.5 | 105.7 | 108.3 | 84.1 | 89.7 | 94.4 | 98.6 | 93.4 | 86.8 | 84.9 | 93.8 | 104.9 |
| 100+ kW | (sec) | 154.6 | 142.8 | 141.9 | 131.3 | 141.5 | 147.2 | 152.7 | 145.1 | 136.9 | 135.0 | 125.1 | 143.1 |
| Primary | (pri) | 3.5 | 3.2 | 2.9 | 3.0 | 3.1 | 3.1 | 3.4 | 3.0 | 3.0 | 3.2 | 2.4 | 2.8 |
| GS - Schedule 30 | | | | | | | | | | | | | |
| 0-300 kW | (sec) | 26.5 | 26.0 | 25.2 | 25.4 | 26.3 | 24.7 | 27.0 | 25.0 | 25.1 | 24.8 | 22.9 | 27.0 |
| 300+ kW | (sec) | 156.6 | 154.4 | 154.8 | 168.9 | 174.4 | 162.4 | 160.8 | 153.1 | 157.5 | 162.7 | 135.7 | 160.2 |
| Primary | (pri) | 12.0 | 11.0 | 10.1 | 12.7 | 11.5 | 10.8 | 11.6 | 10.4 | 10.9 | 11.9 | 11.4 | 10.4 |
| LPS - Schedule 48 | | | | | | | | | | | | | |
| 1 - 4 MW | (sec) | 67.7 | 64.7 | 68.1 | 76.7 | 76.2 | 72.7 | 59.7 | 64.4 | 66.0 | 72.7 | 53.0 | 56.3 |
| 1 - 4 MW | (pri) | 76.6 | 74.3 | 80.7 | 79.4 | 80.5 | 76.3 | 65.3 | 63.5 | 71.0 | 73.6 | 69.3 | 70.2 |
| > 4 MW | (sec) | 13.8 | 16.0 | 15.3 | 15.3 | 15.8 | 16.9 | 12.5 | 13.2 | 13.1 | 13.5 | 14.9 | 14.6 |
| > 4 MW | (pri) | 199.6 | 230.4 | 220.4 | 220.5 | 227.8 | 243.5 | 180.5 | 190.5 | 188.5 | 194.1 | 214.2 | 209.8 |
| Trans | (trn) | 235.5 | 241.7 | 239.8 | 248.7 | 239.7 | 235.4 | 201.4 | 228.4 | 208.8 | 210.3 | 209.9 | 224.0 |
| Irrigation - Sch 41 | (sec) | 75.0 | 65.9 | 60.3 | 12.3 | 1.3 | 1.8 | 1.9 | 1.9 | 3.9 | 17.2 | 51.0 | 76.6 |
| Customer-Owned Lighting - Sch 53 | | - | - | - | - | - | - | - | - | - | - | - | - |
| Rec Field Lighting - Sch 54 | | 0.0 | 0.0 | 0.1 | 0.0 | 0.0 | 0.1 | 0.2 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 |

PacifiCorp
Oregon Marginal Cost Study
Distribution Substations Monthly Peaks - kW
12 months ended June 2021

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | Peak | Peak |
| Substation | | Jul-20 | Aug-20 | Sep-20 | Oct-20 | Nov-20 | Dec-20 | Jan-21 | Feb-21 | Mar-21 | Apr-21 | May-21 | Jun-21 | Month | Load |
| Agness Avenue | | 18,730 | 17,702 | 17,782 | 14,474 | 15,790 | 16,098 | 16,165 | 15,579 | 16,119 | 14,036 | 13,946 | 20,002 | Jun-21 | 20,002 |
| Albina | | 21,282 | 21,405 | 21,346 | 19,076 | 23,551 | 19,109 | 19,045 | 18,950 | 18,043 | 17,427 | 17,422 | 23,099 | Nov-20 | 23,551 |
| Alderwood | | 22,900 | 23,067 | 23,162 | 19,715 | 17,045 | 17,654 | 17,762 | 18,121 | 17,295 | 18,930 | 19,315 | 26,041 | Jun-21 | 26,041 |
| Applegate | | 10,900 | 10,470 | 10,266 | 10,255 | 12,312 | 12,825 | 11,914 | 11,678 | 11,350 | 9,900 | 8,234 | 11,408 | Dec-20 | 12,825 |
| Ashland | | 16,220 | 16,296 | 15,674 | 12,122 | 14,871 | 15,139 | 15,520 | 15,243 | 13,927 | 11,401 | 12,178 | 18,448 | Jun-21 | 18,448 |
| Bandon | | 1,690 | 1,736 | 1,816 | 1,882 | 2,111 | 1,932 | 2,331 | 2,603 | 3,108 | 3,215 | 2,154 | 1,785 | Apr-21 | 3,215 |
| Beall Lane | | 19,563 | 19,148 | 19,289 | 14,464 | 15,861 | 15,529 | 16,158 | 15,731 | 14,691 | 13,261 | 14,400 | 20,457 | Jun-21 | 20,457 |
| Belknap | | 29,469 | 29,666 | 30,457 | 22,319 | 23,748 | 24,265 | 22,529 | 25,572 | 24,398 | 20,554 | 22,878 | 32,660 | Jun-21 | 32,660 |
| Bend Plant | | 19,088 | 16,941 | 18,159 | 14,043 | 14,410 | 15,675 | 15,946 | 16,759 | 12,161 | 10,786 | 11,937 | 22,252 | Jun-21 | 22,252 |
| Bloss | | 10,495 | 10,809 | 11,249 | 10,883 | 11,757 | 11,748 | 10,961 | 11,643 | 11,843 | 10,348 | 11,520 | 10,166 | Mar-21 | 11,843 |
| REDACTED | | 909 | 893 | 864 | 889 | 895 | 951 | 955 | 963 | 909 | 934 | 881 | 917 | Feb-21 | 963 |
| Bond Street | | 15,715 | 14,197 | 14,817 | 13,883 | 13,082 | 14,410 | 14,436 | 14,676 | 12,868 | 11,456 | 10,896 | 21,809 | Jun-21 | 21,809 |
| Brookhurst | | 37,627 | 38,057 | 37,161 | 24,292 | 26,085 | 28,163 | 25,827 | 28,770 | 28,093 | 23,991 | 30,550 | 41,875 | Jun-21 | 41,875 |
| Bryant | | 24,090 | 23,242 | 23,674 | 17,912 | 19,387 | 20,624 | 23,093 | 21,162 | 26,013 | 16,098 | 18,520 | 28,149 | Jun-21 | 28,149 |
| Buchanan | | 22,991 | 21,402 | 22,894 | 22,535 | 22,997 | 23,321 | 25,550 | 24,844 | 21,769 | 20,507 | 17,384 | 27,920 | Jun-21 | 27,920 |
| Buckaroo | | 24,425 | 23,070 | 20,376 | 20,859 | 17,284 | 18,639 | 18,210 | 19,455 | 16,798 | 15,532 | 16,967 | 26,368 | Jun-21 | 26,368 |
| Calapooya | | 5,543 | 5,533 | 5,531 | 5,289 | 5,460 | 5,755 | 5,612 | 5,539 | 5,283 | 4,999 | 4,504 | 6,001 | Jun-21 | 6,001 |
| Campbell | | 24,446 | 24,035 | 24,701 | 22,343 | 23,055 | 16,416 | 16,446 | 15,361 | 14,501 | 12,852 | 16,618 | 23,289 | Sep-20 | 24,701 |
| Cannon Beach | | 4,867 | 4,462 | 4,700 | 6,926 | 6,957 | 6,988 | 7,146 | 7,010 | 6,733 | 6,503 | 4,860 | 4,455 | Jan-21 | 7,146 |
| Canyonville | | 7,502 | 7,628 | 7,135 | 7,217 | 7,385 | 7,933 | 8,117 | 7,588 | 7,976 | 7,858 | 6,552 | 8,218 | Jun-21 | 8,218 |
| Casebeer | | 7,686 | 7,295 | 5,609 | 3,682 | 2,903 | 3,115 | 3,219 | 2,989 | 2,946 | 5,731 | 7,834 | 8,662 | Jun-21 | 8,662 |
| Cave Junction | | 13,336 | 12,650 | 13,309 | 15,296 | 16,778 | 17,359 | 17,939 | 17,316 | 18,383 | 15,749 | 12,370 | 14,339 | Mar-21 | 18,383 |
| Caveman | | 20,812 | 18,927 | 19,818 | 13,966 | 14,715 | 15,328 | 15,173 | 14,022 | 14,739 | 14,490 | 14,059 | 21,698 | Jun-21 | 21,698 |
| Cherry Lane | | 7,551 | 7,536 | 7,387 | 7,616 | 7,315 | 7,379 | 7,419 | 7,322 | 7,406 | 7,539 | 7,309 | 7,279 | Oct-20 | 7,616 |
| Chiloquin | | 7,367 | 7,303 | 8,134 | 7,380 | 7,453 | 6,707 | 7,313 | 7,568 | 7,654 | 7,944 | 7,913 | 7,640 | Sep-20 | 8,134 |
| China Hat | | 19,383 | 17,479 | 17,722 | 20,198 | 19,688 | 20,417 | 21,448 | 21,612 | 19,636 | 18,433 | 15,643 | 22,708 | Jun-21 | 22,708 |
| Circle Blvd | | 18,197 | 15,621 | 15,477 | 15,033 | 14,308 | 13,678 | 14,351 | 14,139 | 14,423 | 14,919 | 14,997 | 17,387 | Jul-20 | 18,197 |
| Cleveland Ave. | | 23,797 | 17,871 | 31,685 | 29,342 | 28,728 | 29,114 | 30,657 | 29,078 | 19,266 | 28,592 | 26,808 | 37,967 | Jun-21 | 37,967 |
| Cloake | | 15,790 | 15,891 | 15,315 | 10,331 | 10,961 | 11,405 | 11,494 | 10,295 | 10,943 | 9,311 | 11,626 | 17,983 | Jun-21 | 17,983 |
| Coburg | | 2,421 | 2,337 | 2,287 | 1,808 | 1,868 | 2,064 | 1,978 | 1,957 | 1,785 | 1,646 | 1,613 | 2,669 | Jun-21 | 2,669 |
| Columbia | | 32,170 | 31,717 | 29,073 | 27,566 | 27,966 | 29,638 | 30,187 | 30,301 | 28,585 | 27,152 | 25,723 | 33,519 | Jun-21 | 33,519 |
| Coquille | | 10,738 | 11,026 | 11,070 | 15,003 | 15,983 | 16,600 | 16,114 | 15,832 | 15,843 | 15,378 | 12,258 | 13,734 | Dec-20 | 16,600 |
| Cully | | 16,959 | 15,050 | 15,493 | 11,608 | 12,696 | 13,956 | 16,748 | 14,955 | 11,948 | 8,514 | 8,849 | 14,783 | Jul-20 | 16,959 |
| Culver | | 7,937 | 6,797 | 6,359 | 7,362 | 8,989 | 8,286 | 8,733 | 8,676 | 7,561 | 6,677 | 6,258 | 8,642 | Nov-20 | 8,989 |
| Dairy | | 10,746 | 8,546 | 6,609 | 4,092 | 2,778 | 2,863 | 2,715 | 2,599 | 2,667 | 6,904 | 8,937 | 10,113 | Jul-20 | 10,746 |
| Dallas | | 33,210 | 32,488 | 32,656 | 29,034 | 32,177 | 34,353 | 32,569 | 34,426 | 32,147 | 29,580 | 26,016 | 39,591 | Jun-21 | 39,591 |
| Dalreed | | 53,302 | 56,191 | 46,640 | 21,494 | 8,287 | 7,941 | 8,926 | 8,091 | 21,448 | 28,174 | 44,570 | 52,844 | Aug-20 | 56,191 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Deschutes | 8,265 | 7,343 | 7,406 | 10,982 | 9,998 | 11,562 | 12,035 | 12,116 | 10,548 | 8,916 | 6,886 | 9,433 | Feb-21 | 12,116 |
| Devils Lake | 20,257 | 19,422 | 20,008 | 28,083 | 29,641 | 31,539 | 32,217 | 32,116 | 30,833 | 28,233 | 22,730 | 20,932 | Jan-21 | 32,217 |
| Dixon | 3,383 | 3,117 | 3,375 | 2,490 | 2,304 | 2,436 | 2,458 | 2,509 | 2,166 | 2,327 | 2,468 | 3,575 | Jun-21 | 3,575 |
| Dodge Bridge | 11,371 | 11,622 | 11,046 | 10,055 | 11,199 | 13,422 | 10,668 | 16,425 | 10,813 | 9,246 | 9,015 | 12,466 | Feb-21 | 16,425 |
| Dowell | 16,290 | 16,092 | 15,468 | 10,518 | 12,173 | 12,729 | 12,185 | 11,480 | 11,890 | 9,861 | 12,452 | 17,655 | Jun-21 | 17,655 |
| Easy Valley | 19,935 | 20,730 | 18,603 | 14,098 | 16,809 | 17,194 | 16,738 | 15,759 | 16,084 | 13,081 | 14,942 | 22,436 | Jun-21 | 22,436 |
| Empire | 9,962 | 8,833 | 10,420 | 15,387 | 17,404 | 18,610 | 18,370 | 18,710 | 17,895 | 16,370 | 12,185 | 10,479 | Feb-21 | 18,710 |
| Fern Hill | 1,812 | 1,847 | 2,068 | 2,794 | 3,293 | 3,309 | 3,362 | 3,889 | 2,539 | 2,400 | 1,544 | 1,417 | Feb-21 | 3,889 |
| Fielder Creek | 11,024 | 10,498 | 10,417 | 11,372 | 11,527 | 11,794 | 12,164 | 11,416 | 12,085 | 10,819 | 8,260 | 12,117 | Jan-21 | 12,164 |
| Foothills Rd | 13,928 | 13,810 | 13,848 | 10,034 | 8,855 | 11,263 | 11,122 | 10,875 | 9,746 | 8,989 | 11,674 | 15,529 | Jun-21 | 15,529 |
| Garden Valley | 14,841 | 12,336 | 14,480 | 10,888 | 10,633 | 10,592 | 10,310 | 9,553 | 10,165 | 9,181 | 11,120 | 16,317 | Jun-21 | 16,317 |
| Glendale | 9,818 | 9,816 | 9,275 | 12,291 | 11,926 | 12,249 | 11,734 | 11,736 | 11,684 | 11,373 | 10,549 | 11,703 | Oct-20 | 12,291 |
| Gold Hill | 8,164 | 8,088 | 7,907 | 7,008 | 8,035 | 8,496 | 7,882 | 7,675 | 7,629 | 6,715 | 6,547 | 8,668 | Jun-21 | 8,668 |
| Gordon Hollow | 4,585 | 4,032 | 3,799 | 3,755 | 3,533 | 3,956 | 3,848 | 4,690 | 3,536 | 3,259 | 3,250 | 4,489 | Feb-21 | 4,690 |
| Goshen | 5,613 | 5,600 | 5,347 | 5,848 | 5,672 | 6,356 | 6,309 | 6,143 | 5,768 | 5,463 | 4,155 | 6,258 | Dec-20 | 6,356 |
| Grant Street | 24,072 | 24,817 | 24,947 | 22,661 | 25,315 | 26,565 | 29,174 | 28,523 | 23,985 | 21,096 | 21,475 | 28,826 | Jan-21 | 29,174 |
| Green | 14,435 | 14,243 | 14,093 | 12,789 | 13,179 | 13,682 | 13,922 | 12,465 | 13,470 | 11,947 | 11,092 | 15,604 | Jun-21 | 15,604 |
| Harrisburg | 8,308 | 7,305 | 7,374 | 7,680 | 8,051 | 8,741 | 8,538 | 8,432 | 8,423 | 7,104 | 5,710 | 8,485 | Dec-20 | 8,741 |
| Hazelwood | 7,296 | 7,303 | 7,129 | 6,509 | 6,530 | 6,686 | 6,747 | 6,581 | 6,412 | 5,583 | 4,804 | 7,681 | Jun-21 | 7,681 |
| Hillview | 28,199 | 24,717 | 29,902 | 23,168 | 24,427 | 25,185 | 23,912 | 24,989 | 24,936 | 20,954 | 20,670 | 31,463 | Jun-21 | 31,463 |
| Holladay | 22,638 | 21,269 | 21,060 | 18,559 | 17,270 | 18,078 | 18,619 | 18,787 | 16,240 | 16,627 | 15,606 | 21,230 | Jul-20 | 22,638 |
| Hollywood | 31,334 | 30,111 | 30,065 | 22,562 | 24,372 | 25,857 | 24,136 | 29,650 | 24,040 | 23,818 | 22,364 | 35,974 | Jun-21 | 35,974 |
| Hood River | 29,865 | 28,567 | 28,247 | 25,171 | 24,399 | 31,263 | 26,571 | 30,603 | 24,427 | 21,559 | 22,183 | 35,540 | Jun-21 | 35,540 |
| Hornet | 15,063 | 15,749 | 15,327 | 11,174 | 11,274 | 11,874 | 10,749 | 11,078 | 11,302 | 9,782 | 12,038 | 17,381 | Jun-21 | 17,381 |
| Independence | 21,249 | 20,788 | 20,746 | 16,646 | 16,983 | 17,870 | 18,428 | 18,988 | 17,258 | 15,311 | 16,531 | 23,969 | Jun-21 | 23,969 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jacksonville | 17,658 | 18,271 | 17,233 | 12,144 | 14,496 | 15,086 | 15,130 | 14,651 | 14,060 | 11,879 | 13,446 | 20,264 | Jun-21 | 20,264 |
| Jefferson | 8,957 | 8,992 | 9,194 | 9,866 | 10,418 | 10,763 | 10,812 | 11,209 | 11,031 | 10,119 | 9,887 | 11,758 | Jun-21 | 11,758 |
| Jerome Prairie | 13,395 | 13,402 | 12,613 | 13,363 | 15,930 | 15,742 | 14,381 | 14,854 | 15,015 | 12,636 | 10,978 | 15,843 | Nov-20 | 15,930 |
| Junction City | 8,095 | 8,288 | 8,096 | 8,179 | 8,647 | 9,228 | 8,821 | 8,988 | 8,615 | 7,580 | 6,394 | 8,346 | Dec-20 | 9,228 |
| Killingsworth | 23,499 | 22,569 | 20,594 | 23,354 | 23,812 | 23,557 | 24,256 | 25,179 | 22,303 | 12,947 | 11,630 | 20,470 | Feb-21 | 25,179 |
| Knappa Svensen | 2,828 | 2,943 | 2,847 | 3,971 | 4,381 | 4,500 | 5,097 | 4,934 | 4,703 | 4,397 | 3,074 | 3,471 | Jan-21 | 5,097 |
| Knott | 19,580 | 19,552 | 19,282 | 21,210 | 22,420 | 23,845 | 28,965 | 28,967 | 24,193 | 21,484 | 19,631 | 31,719 | Jun-21 | 31,719 |
| Lakeport | 17,545 | 17,584 | 18,155 | 17,502 | 18,414 | 18,695 | 19,825 | 19,264 | 19,102 | 17,296 | 16,407 | 18,452 | Jan-21 | 19,825 |
| Lancaster | 8,022 | 7,850 | 7,845 | 6,892 | 7,556 | 6,861 | 9,051 | 8,785 | 8,555 | 7,510 | 6,140 | 7,015 | Jan-21 | 9,051 |
| Lebanon | 30,414 | 30,909 | 29,185 | 27,620 | 27,547 | 29,718 | 28,491 | 29,369 | 26,880 | 25,003 | 23,760 | 35,795 | Jun-21 | 35,795 |
| Lincoln | 19,472 | 19,650 | 18,878 | 19,108 | 18,901 | 19,048 | 18,885 | 21,055 | 18,625 | 17,424 | 16,173 | 22,534 | Jun-21 | 22,534 |
| Lockhart | 11,476 | 14,458 | 11,512 | 17,954 | 20,180 | 21,837 | 21,351 | 21,406 | 21,756 | 20,086 | 14,491 | 12,029 | Dec-20 | 21,837 |
| Lyons | 18,342 | 18,142 | 16,978 | 18,222 | 19,639 | 19,794 | 20,354 | 19,864 | 19,953 | 19,209 | 17,797 | 18,398 | Jan-21 | 20,354 |
| Madras | 18,690 | 16,568 | 16,737 | 17,805 | 17,372 | 18,453 | 19,533 | 20,259 | 16,828 | 16,462 | 14,419 | 21,583 | Jun-21 | 21,583 |
| Mallory | 13,639 | 12,923 | 12,581 | 10,176 | 11,245 | 11,806 | 12,392 | 13,812 | 10,625 | 9,363 | 8,811 | 15,226 | Jun-21 | 15,226 |
| Marys River | 14,668 | 13,583 | 14,294 | 14,584 | 14,753 | 15,119 | 15,080 | 15,022 | 14,225 | 13,120 | 12,231 | 14,792 | Dec-20 | 15,119 |
| Medford | 24,526 | 24,011 | 24,566 | 18,541 | 17,154 | 18,434 | 18,304 | 17,677 | 16,034 | 16,395 | 19,167 | 27,686 | Jun-21 | 27,686 |
| Merlin | 23,152 | 22,909 | 22,847 | 25,141 | 27,216 | 28,403 | 29,137 | 25,571 | 29,699 | 21,676 | 19,455 | 25,716 | Mar-21 | 29,699 |
| Merrill | 8,824 | 8,612 | 8,147 | 4,375 | 4,773 | 4,854 | 5,112 | 4,867 | 4,796 | 6,308 | 7,109 | 9,355 | Jun-21 | 9,355 |
| Mile High | 10,108 | 9,485 | 10,286 | 11,120 | 11,763 | 12,708 | 12,593 | 12,648 | 12,555 | 11,190 | 10,229 | 10,563 | Dec-20 | 12,708 |
| Murder Creek | 41,616 | 58,603 | 51,206 | 46,686 | 47,405 | 51,125 | 50,902 | 48,828 | 45,494 | 44,449 | 42,305 | 55,784 | Aug-20 | 58,603 |
| Oak Knoll | 19,300 | 19,169 | 18,208 | 14,870 | 18,395 | 19,241 | 19,892 | 19,749 | 18,818 | 14,449 | 14,256 | 22,700 | Jun-21 | 22,700 |
| O'Brien | 1,384 | 1,257 | 1,243 | 1,417 | 1,518 | 1,646 | 1,630 | 1,554 | 1,661 | 1,428 | 1,188 | 1,395 | Mar-21 | 1,661 |
| REDACTED | 23,526 | 27,074 | 27,562 | 22,689 | 22,040 | 21,948 | 19,207 | 18,655 | 18,344 | 15,939 | 14,935 | 19,730 | Sep-20 | 27,562 |
| Overpass | 36,882 | 36,533 | 34,648 | 34,570 | 33,884 | 36,105 | 36,946 | 37,699 | 34,284 | 26,986 | 29,935 | 38,263 | Jun-21 | 38,263 |
| Pallette | 353 | 349 | 295 | 417 | 477 | 465 | 465 | 486 | 407 | 416 | 292 | 453 | Feb-21 | 486 |
| Park Street | 33,117 | 31,630 | 31,935 | 22,481 | 25,656 | 27,997 | 26,418 | 25,256 | 25,788 | 21,343 | 22,736 | 34,659 | Jun-21 | 34,659 |
| Parkrose | 27,509 | 28,524 | 27,154 | 23,633 | 25,161 | 26,563 | 27,978 | 31,467 | 24,964 | 22,422 | 21,327 | 33,225 | Jun-21 | 33,225 |
| Pendleton | 30,942 | 28,440 | 25,080 | 18,690 | 19,712 | 21,383 | 21,170 | 23,806 | 21,160 | 21,770 | 19,154 | 33,400 | Jun-21 | 33,400 |
| Pilot Butte | 18,542 | 16,398 | 17,002 | 13,898 | 13,585 | 15,086 | 14,639 | 15,193 | 12,602 | 11,359 | 12,370 | 20,739 | Jun-21 | 20,739 |
| Prineville | 35,527 | 35,207 | 32,901 | 23,824 | 32,702 | 36,450 | 40,005 | 35,670 | 32,138 | 31,935 | 29,234 | 40,843 | Jun-21 | 40,843 |
| Prospect Central | 2,189 | 2,408 | 3,144 | 1,868 | 4,311 | 5,147 | 5,304 | 5,530 | 3,134 | 4,523 | 3,695 | 2,194 | Feb-21 | 5,530 |
| Queen Ave | 36,131 | 35,932 | 36,236 | 26,041 | 28,377 | 31,084 | 32,023 | 31,063 | 27,641 | 25,452 | 28,156 | 42,219 | Jun-21 | 42,219 |
| Redmond 115 | 37,865 | 36,811 | 35,176 | 35,879 | 33,204 | 37,260 | 38,675 | 36,886 | 33,347 | 31,827 | 26,933 | 41,483 | Jun-21 | 41,483 |
| Riddle | 17,437 | 15,808 | 15,011 | 17,230 | 17,790 | 16,244 | 17,612 | 17,380 | 17,711 | 15,911 | 13,479 | 17,507 | Nov-20 | 17,790 |
| REDACTED | 11,366 | 11,091 | 11,159 | 11,563 | 11,213 | 11,862 | 11,683 | 11,665 | 12,016 | 12,137 | 11,670 | 11,478 | Apr-21 | 12,137 |
| Roseburg | 22,614 | 21,815 | 21,701 | 19,499 | 20,560 | 20,820 | 21,252 | 20,133 | 20,499 | 17,668 | 15,119 | 24,846 | Jun-21 | 24,846 |
| Ross Ave | 7,199 | 6,993 | 7,159 | 5,379 | 5,623 | 6,080 | 6,528 | 6,028 | 6,041 | 5,010 | 5,390 | 7,995 | Jun-21 | 7,995 |
| Roxy Ann | 15,252 | 15,494 | 16,024 | 9,377 | 7,867 | 7,982 | 8,175 | 7,207 | 6,849 | 6,306 | 11,396 | 16,977 | Jun-21 | 16,977 |
| Russelville | 28,472 | 28,202 | 27,605 | 24,581 | 26,687 | 28,242 | 29,765 | 33,495 | 25,502 | 23,010 | 22,229 | 33,803 | Jun-21 | 33,803 |
| Sage Road | 31,627 | 31,030 | 31,720 | 24,004 | 23,852 | 28,937 | 29,179 | 24,214 | 22,422 | 21,262 | 22,690 | 34,005 | Jun-21 | 34,005 |
| Scenic | 28,959 | 29,133 | 28,859 | 19,245 | 19,577 | 21,459 | 20,016 | 19,793 | 18,625 | 15,803 | 23,723 | 32,058 | Jun-21 | 32,058 |
| Scio | 5,137 | 5,332 | 5,171 | 5,118 | 5,339 | 5,576 | 5,326 | 5,361 | 5,235 | 4,891 | 4,263 | 5,833 | Jun-21 | 5,833 |
| Seaside | 15,101 | 15,040 | 15,752 | 18,082 | 19,829 | 21,204 | 21,638 | 21,131 | 19,452 | 18,506 | 14,816 | 14,955 | Jan-21 | 21,638 |
| Shevlin Park | 23,274 | 20,265 | 22,070 | 16,466 | 16,973 | 18,659 | 18,814 | 19,343 | 15,501 | 13,989 | 14,751 | 28,007 | Jun-21 | 28,007 |
| Southgate | 13,786 | 14,482 | 14,313 | 12,871 | 13,367 | 12,998 | 14,371 | 12,762 | 13,554 | 12,122 | 10,919 | 17,030 | Jun-21 | 17,030 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| State Street | 18,366 | 18,603 | 19,309 | 27,295 | 31,675 | 33,886 | 33,119 | 32,046 | 32,628 | 29,156 | 23,766 | 19,005 | Dec-20 | 33,886 |
| Stayton | 33,538 | 33,866 | 32,063 | 31,038 | 31,469 | 33,886 | 32,756 | 32,307 | 31,694 | 29,172 | 25,167 | 40,815 | Jun-21 | 40,815 |
| Stevens Road | 22,961 | 23,777 | 22,361 | 13,961 | 16,268 | 17,769 | 18,383 | 18,097 | 15,502 | 12,876 | 18,932 | 26,945 | Jun-21 | 26,945 |
| Sutherlin | 11,549 | 11,616 | 11,257 | 11,421 | 11,730 | 11,288 | 11,675 | 11,207 | 11,075 | 10,317 | 8,283 | 13,088 | Jun-21 | 13,088 |
| Sweet Home | 22,385 | 22,268 | 21,916 | 25,370 | 25,583 | 25,283 | 24,438 | 24,361 | 24,388 | 22,327 | 17,081 | 26,191 | Jun-21 | 26,191 |
| Takelma | 8,921 | 9,235 | 8,463 | 8,727 | 9,950 | 10,876 | 10,090 | 10,544 | 9,510 | 8,490 | 6,929 | 10,272 | Dec-20 | 10,876 |
| Talent | 22,760 | 22,288 | 22,651 | 14,851 | 18,005 | 19,046 | 18,624 | 18,066 | 16,736 | 13,997 | 14,539 | 20,947 | Jul-20 | 22,760 |
| Texum | 12,305 | 11,181 | 12,033 | 11,379 | 11,348 | 12,628 | 15,313 | 15,053 | 11,806 | 10,042 | 8,891 | 12,405 | Jan-21 | 15,313 |
| Umatilla | 14,925 | 14,016 | 13,252 | 10,117 | 9,466 | 10,410 | 14,100 | 14,390 | 9,464 | 9,193 | 12,289 | 16,055 | Jun-21 | 16,055 |
| Vernon | 36,464 | 34,454 | 33,321 | 25,939 | 28,449 | 30,609 | 32,992 | 33,277 | 27,071 | 21,090 | 21,628 | 38,048 | Jun-21 | 38,048 |
| Vilas Road | 20,441 | 19,906 | 20,166 | 14,944 | 14,568 | 15,228 | 14,935 | 15,441 | 15,994 | 18,883 | 14,893 | 23,455 | Jun-21 | 23,455 |
| Village Green | 13,122 | 13,069 | 12,499 | 13,076 | 13,041 | 14,092 | 13,901 | 13,833 | 13,053 | 12,294 | 10,044 | 14,979 | Jun-21 | 14,979 |
| Vine Street | 27,967 | 23,103 | 22,171 | 14,241 | 15,470 | 16,930 | 16,437 | 20,532 | 16,935 | 16,477 | 21,039 | 27,204 | Jul-20 | 27,967 |
| Warrenton | 16,751 | 17,642 | 16,931 | 16,787 | 18,235 | 18,655 | 19,792 | 19,722 | 18,420 | 17,721 | 15,639 | 16,341 | Jan-21 | 19,792 |
| Weston | 9,336 | 10,982 | 9,944 | 9,540 | 8,887 | 6,245 | 6,370 | 6,356 | 5,928 | 6,024 | 4,983 | 10,058 | Aug-20 | 10,982 |
| Westside | 13,076 | 12,755 | 12,474 | 11,827 | 13,076 | 13,697 | 14,399 | 13,857 | 13,241 | 11,760 | 11,460 | 15,237 | Jun-21 | 15,237 |
| White City | 42,105 | 41,170 | 40,151 | 36,004 | 36,552 | 38,317 | 37,949 | 38,055 | 37,150 | 38,113 | 33,796 | 43,384 | Jun-21 | 43,384 |
| Winchester | 23,810 | 25,277 | 23,089 | 19,401 | 20,231 | 19,529 | 20,666 | 19,138 | 20,129 | 17,567 | 16,937 | 26,217 | Jun-21 | 26,217 |
| Yew Ave | 17,572 | 16,325 | 16,409 | 15,058 | 14,114 | 16,524 | 17,140 | 17,413 | 14,554 | 13,635 | 13,382 | 21,806 | Jun-21 | 21,806 |
| | | | | | | | | | | | | | Total | |
| Substation Peaks | 119,268 | 125,776 | 60,398 | 19,907 | 66,261 | 148,176 | 191,772 | 87,988 | 61,586 | 15,352 | - | 1,747,014 | 2,643,497 | |
| Weighting Factor | 4.51% | 4.76% | 2.28% | 0.75% | 2.51% | 5.61% | 7.25% | 3.33% | 2.33% | 0.58% | 0.00% | 66.09% | 100.00% | |

PacifiCorp
Oregon Marginal Cost Study
Distribution Substations Monthly Peaks - kW
12 months ended June 2022

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Substation | | Jul-21 | Aug-21 | Sep-21 | Oct-21 | Nov-21 | Dec-21 | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Peak Month | Peak Load |
| Agness Avenue | | 18,360 | 17,810 | 15,536 | 13,999 | 15,376 | 17,577 | 16,511 | 16,458 | 15,327 | 14,251 | 13,431 | 16,037 | Jul-21 | 18,360 |
| Albina | | 23,488 | 24,578 | 20,749 | 23,309 | 20,040 | 20,568 | 20,667 | 20,834 | 18,955 | 19,793 | 18,977 | 21,946 | Aug-21 | 24,578 |
| Alderwood | | 22,657 | 24,228 | 21,423 | 18,032 | 18,147 | 18,855 | 18,786 | 19,076 | 24,400 | 17,885 | 18,670 | 23,954 | Mar-22 | 24,400 |
| Applegate | | 10,467 | 10,419 | 8,497 | 10,153 | 11,317 | 11,032 | 12,847 | 13,213 | 11,444 | 10,887 | 9,114 | 9,502 | Feb-22 | 13,213 |
| Ashland | | 16,012 | 15,921 | 12,458 | 12,440 | 14,173 | 15,415 | 15,270 | 16,351 | 13,736 | 13,493 | 12,248 | 15,069 | Feb-22 | 16,351 |
| Bandon | | 1,791 | 2,003 | 1,987 | 2,370 | 2,257 | 2,520 | 2,482 | 3,164 | 3,023 | 3,236 | 2,795 | 2,416 | Apr-22 | 3,236 |
| Beall Lane | | 19,708 | 18,977 | 15,442 | 13,931 | 14,690 | 15,076 | 16,683 | 16,757 | 14,978 | 14,136 | 13,921 | 17,888 | Jul-21 | 19,708 |
| Belknap | | 28,978 | 29,637 | 24,326 | 19,915 | 21,479 | 22,387 | 23,188 | 23,781 | 21,177 | 19,778 | 21,529 | 26,814 | Aug-21 | 29,637 |
| Bend Plant | | 18,300 | 19,387 | 14,487 | 11,210 | 12,370 | 16,662 | 14,738 | 15,886 | 13,814 | 11,982 | 10,629 | 16,097 | Aug-21 | 19,387 |
| Bloss | | 10,171 | 11,626 | 11,974 | 10,170 | 10,025 | 9,668 | 9,634 | 11,212 | 9,752 | 10,912 | 8,954 | 9,580 | Sep-21 | 11,974 |
| Bly | | 1,910 | 1,699 | 1,422 | 1,146 | 1,002 | 1,040 | 1,211 | 1,177 | 1,083 | 1,067 | 1,447 | 2,088 | Jun-22 | 2,088 |
| REDACTED | | 928 | 895 | 875 | 930 | 968 | 957 | 921 | 926 | 893 | 893 | 922 | 917 | Nov-21 | 968 |
| Bond Street | | 18,359 | 18,900 | 14,099 | 13,523 | 14,500 | 18,381 | 16,762 | 18,881 | 16,531 | 14,001 | 13,055 | 16,649 | Aug-21 | 18,900 |
| Brookhurst | | 36,233 | 36,749 | 28,258 | 22,160 | 23,488 | 25,742 | 26,517 | 28,379 | 23,802 | 21,297 | 23,212 | 35,842 | Aug-21 | 36,749 |
| Bryant | | 25,767 | 25,441 | 21,884 | 16,959 | 18,862 | 22,680 | 22,318 | 22,485 | 19,260 | 18,992 | 17,443 | 21,935 | Jul-21 | 25,767 |
| Buchanan | | 24,031 | 27,782 | 22,903 | 20,813 | 24,046 | 24,260 | 26,715 | 25,479 | 22,647 | 22,246 | 19,861 | 21,390 | Aug-21 | 27,782 |
| Buckaroo | | 23,488 | 24,700 | 18,962 | 16,493 | 18,115 | 19,804 | 20,060 | 19,001 | 16,417 | 12,331 | 11,740 | 14,701 | Aug-21 | 24,700 |
| Calapooya | | 5,551 | 5,785 | 5,054 | 4,589 | 5,402 | 5,455 | 5,031 | 5,437 | 5,429 | 4,988 | 4,692 | 4,867 | Aug-21 | 5,785 |
| Campbell | | 20,546 | 20,428 | 16,221 | 14,069 | 15,347 | 15,844 | 16,130 | 16,141 | 13,068 | 12,089 | 12,244 | 16,291 | Jul-21 | 20,546 |
| Cannon Beach | | 4,897 | 4,373 | 4,499 | 5,470 | 6,458 | 7,949 | 9,023 | 8,068 | 6,292 | 6,578 | 5,787 | 4,414 | Jan-22 | 9,023 |
| Canyonville | | 7,238 | 7,691 | 7,434 | 6,965 | 7,659 | 8,020 | 8,048 | 8,290 | 7,737 | 7,867 | 6,702 | 7,419 | Feb-22 | 8,290 |
| Casebeer | | 8,799 | 6,785 | 5,930 | 2,646 | 2,771 | 3,062 | 5,880 | 3,347 | 2,967 | 4,114 | 6,905 | 6,849 | Jul-21 | 8,799 |
| Cave Junction | | 14,263 | 14,145 | 11,556 | 15,100 | 16,133 | 15,977 | 17,542 | 18,478 | 16,282 | 16,662 | 14,879 | 11,395 | Feb-22 | 18,478 |
| Caveman | | 20,547 | 20,116 | 17,007 | 12,151 | 13,749 | 18,232 | 15,650 | 15,535 | 13,603 | 12,726 | 13,226 | 17,383 | Jul-21 | 20,547 |
| Cherry Lane | | 7,333 | 7,294 | 7,174 | 7,321 | 7,410 | 7,317 | 7,480 | 7,510 | 7,285 | 9,686 | 9,661 | 7,093 | Apr-22 | 9,686 |
| Chiloquin | | 7,415 | 7,623 | 7,661 | 7,605 | 7,137 | 6,988 | 7,167 | 7,285 | 7,597 | 7,504 | 7,247 | 7,918 | Jun-22 | 7,918 |
| China Hat | | 19,124 | 20,869 | 15,318 | 18,955 | 20,164 | 22,467 | 23,518 | 25,672 | 22,931 | 18,489 | 17,870 | 17,699 | Feb-22 | 25,672 |
| Circle Blvd | | 15,760 | 17,017 | 15,190 | 14,716 | 14,301 | 13,979 | 13,677 | 14,084 | 14,511 | 14,611 | 15,527 | 15,965 | Aug-21 | 17,017 |
| Cleveland Ave. | | 33,272 | 34,937 | 28,196 | 25,986 | 28,432 | 32,367 | 30,609 | 33,674 | 32,082 | 32,913 | 25,593 | 31,229 | Aug-21 | 34,937 |
| Cloake | | 15,994 | 16,327 | 13,130 | 8,880 | 10,616 | 12,023 | 11,374 | 12,901 | 10,751 | 10,455 | 8,731 | 15,297 | Aug-21 | 16,327 |
| Coburg | | 2,477 | 2,654 | 2,096 | 1,584 | 1,831 | 2,155 | 2,159 | 2,257 | 1,946 | 1,830 | 1,617 | 2,245 | Aug-21 | 2,654 |
| Columbia | | 32,808 | 33,566 | 28,103 | 25,154 | 27,217 | 28,391 | 29,359 | 28,865 | 26,578 | 24,306 | 23,104 | 28,272 | Aug-21 | 33,566 |
| Coquille | | 10,402 | 13,380 | 11,039 | 13,319 | 15,152 | 16,527 | 16,285 | 17,608 | 15,324 | 15,521 | 13,554 | 11,046 | Feb-22 | 17,608 |
| Cully | | 12,152 | 13,652 | 10,055 | 8,756 | 9,707 | 11,241 | 11,207 | 10,632 | 9,551 | 7,711 | 7,002 | 9,814 | Aug-21 | 13,652 |
| Culver | | 9,544 | 7,052 | 6,430 | 6,573 | 7,050 | 8,402 | 8,547 | 10,040 | 8,439 | 6,824 | 5,623 | 5,905 | Feb-22 | 10,040 |
| Dairy | | 10,144 | 8,483 | 7,094 | 2,569 | 3,909 | 2,904 | 3,034 | 2,607 | 2,992 | 4,605 | 8,516 | 8,335 | Jul-21 | 10,144 |
| Dallas | | 35,885 | 39,087 | 29,229 | 27,599 | 30,710 | 35,004 | 35,635 | 38,644 | 33,378 | 32,094 | 26,849 | 32,328 | Aug-21 | 39,087 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Dalreed | 53,434 | 49,732 | 36,996 | 17,533 | 8,146 | 8,107 | 10,165 | 7,926 | 22,084 | 25,749 | 33,617 | 47,030 | Jul-21 | 53,434 |
| Deschutes | 8,473 | 8,562 | 6,901 | 9,314 | 10,257 | 11,432 | 13,537 | 14,701 | 12,638 | 9,681 | 8,708 | 7,266 | Feb-22 | 14,701 |
| Devils Lake | 19,818 | 18,962 | 20,057 | 24,170 | 28,641 | 35,306 | 34,722 | 34,824 | 28,525 | 28,387 | 25,849 | 20,739 | Dec-21 | 35,306 |
| Dixon | 3,577 | 3,837 | 3,024 | 2,165 | 2,395 | 2,605 | 2,723 | 2,686 | 2,299 | 2,366 | 2,489 | 3,007 | Aug-21 | 3,837 |
| Dodge Bridge | 11,274 | 15,619 | 13,930 | 15,412 | 15,191 | 10,871 | 11,849 | 12,955 | 10,957 | 10,272 | 8,717 | 10,175 | Aug-21 | 15,619 |
| Dowell | 16,102 | 16,070 | 13,398 | 10,843 | 11,993 | 12,605 | 13,359 | 13,900 | 12,110 | 11,375 | 10,489 | 15,047 | Jul-21 | 16,102 |
| Easy Valley | 19,981 | 19,758 | 16,152 | 13,556 | 15,775 | 16,881 | 17,570 | 18,299 | 15,373 | 15,156 | 11,634 | 18,352 | Jul-21 | 19,981 |
| Empire | 9,939 | 11,539 | 11,178 | 14,466 | 16,900 | 19,688 | 18,946 | 20,681 | 17,756 | 16,841 | 14,257 | 10,426 | Feb-22 | 20,681 |
| Fern Hill | 1,154 | 1,622 | 2,129 | 2,597 | 2,976 | 3,168 | 2,779 | 2,670 | 2,646 | 2,097 | 1,762 | 1,462 | Dec-21 | 3,168 |
| Fielder Creek | 11,693 | 11,522 | 9,557 | 10,514 | 10,771 | 11,256 | 12,274 | 13,147 | 11,785 | 11,169 | 9,013 | 9,566 | Feb-22 | 13,147 |
| Foothills Rd | 13,944 | 13,690 | 11,008 | 9,526 | 10,014 | 10,360 | 10,641 | 11,057 | 10,093 | 9,507 | 9,957 | 13,398 | Jul-21 | 13,944 |
| Garden Valley | 15,086 | 15,396 | 12,601 | 8,706 | 10,851 | 10,322 | 10,538 | 11,139 | 9,694 | 9,560 | 9,468 | 13,486 | Aug-21 | 15,396 |
| Glendale | 10,247 | 9,902 | 8,863 | 11,307 | 11,567 | 12,275 | 13,390 | 13,965 | 12,774 | 12,201 | 11,161 | 9,404 | Feb-22 | 13,965 |
| Gold Hill | 8,332 | 8,009 | 6,388 | 6,885 | 7,422 | 7,350 | 8,326 | 9,076 | 7,683 | 7,447 | 6,021 | 7,396 | Feb-22 | 9,076 |
| Gordon Hollow | 4,345 | 4,641 | 3,304 | 3,253 | 3,704 | 4,999 | 5,076 | 5,376 | 4,168 | 3,653 | 3,070 | 3,739 | Feb-22 | 5,376 |
| Goshen | 5,653 | 6,368 | 5,149 | 5,032 | 5,709 | 6,636 | 6,517 | 7,142 | 6,205 | 5,866 | 4,994 | 5,515 | Feb-22 | 7,142 |
| Grant Street | 25,993 | 28,697 | 21,885 | 21,890 | 27,043 | 26,731 | 28,665 | 28,335 | 24,238 | 23,433 | 20,707 | 23,580 | Aug-21 | 28,697 |
| Green | 14,471 | 14,686 | 12,564 | 10,044 | 12,576 | 13,624 | 13,496 | 15,740 | 12,997 | 12,581 | 10,581 | 13,699 | Feb-22 | 15,740 |
| Harrisburg | 7,989 | 8,426 | 6,816 | 6,798 | 7,716 | 8,529 | 8,793 | 9,290 | 8,053 | 7,232 | 6,531 | 7,040 | Feb-22 | 9,290 |
| Hazelwood | 6,869 | 7,343 | 5,490 | 6,052 | 6,272 | 6,866 | 7,332 | 7,226 | 6,461 | 5,960 | 5,406 | 5,821 | Aug-21 | 7,343 |
| Hillview | 26,312 | 33,010 | 26,248 | 20,463 | 24,276 | 24,976 | 30,881 | 25,849 | 24,648 | 20,879 | 20,548 | 29,411 | Aug-21 | 33,010 |
| Holladay | 19,870 | 21,863 | 20,823 | 17,386 | 17,109 | 19,584 | 18,376 | 18,755 | 16,105 | 16,590 | 15,734 | 20,056 | Aug-21 | 21,863 |
| Hollywood | 30,476 | 34,728 | 26,509 | 19,930 | 22,168 | 26,706 | 26,053 | 25,532 | 22,255 | 23,022 | 19,626 | 30,942 | Aug-21 | 34,728 |
| Hood River | 30,542 | 33,059 | 24,641 | 21,137 | 24,366 | 31,061 | 32,061 | 31,219 | 26,103 | 24,120 | 21,360 | 27,153 | Aug-21 | 33,059 |
| Hornet | 15,832 | 15,608 | 12,948 | 10,205 | 11,389 | 12,930 | 12,689 | 13,423 | 11,505 | 11,176 | 10,404 | 13,615 | Jul-21 | 15,832 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Independence | 22,197 | 23,683 | 18,846 | 15,057 | 16,750 | 18,513 | 18,928 | 19,358 | 16,862 | 16,168 | 13,572 | 16,468 | Aug-21 | 23,683 |
| Jacksonville | 17,629 | 17,367 | 12,312 | 12,250 | 13,728 | 14,537 | 15,365 | 16,271 | 14,068 | 13,207 | 11,344 | 15,864 | Jul-21 | 17,629 |
| Jefferson | 10,393 | 11,559 | 11,162 | 8,639 | 9,521 | 11,556 | 16,304 | 17,200 | 14,573 | 14,392 | 10,600 | 12,526 | Feb-22 | 17,200 |
| Jerome Prairie | 14,427 | 14,604 | 11,014 | 13,049 | 14,491 | 14,311 | 9,309 | 9,565 | 8,472 | 8,061 | 7,026 | 7,455 | Aug-21 | 14,604 |
| Junction City | 8,014 | 8,835 | 7,409 | 7,003 | 8,270 | 9,166 | 17,143 | 17,465 | 15,881 | 16,289 | 14,366 | 17,631 | Jun-22 | 17,631 |
| Killingsworth | 18,649 | 20,251 | 16,214 | 15,309 | 16,709 | 18,770 | 18,863 | 19,400 | 17,628 | 20,597 | 14,658 | 19,740 | Apr-22 | 20,597 |
| Knappa Svensen | 2,806 | 3,167 | 2,827 | 3,796 | 5,044 | 5,363 | 4,934 | 5,252 | 4,676 | 4,486 | 3,768 | 3,179 | Dec-21 | 5,363 |
| Knott | 26,984 | 30,684 | 23,720 | 20,636 | 24,209 | 28,683 | 27,006 | 26,796 | 24,522 | 23,955 | 20,267 | 26,468 | Aug-21 | 30,684 |
| Lakeport | 18,043 | 17,594 | 15,960 | 16,092 | 17,810 | 19,073 | 19,057 | 19,418 | 17,939 | 17,835 | 17,544 | 15,882 | Feb-22 | 19,418 |
| Lancaster | 6,586 | 6,773 | 7,950 | 8,524 | 10,275 | 10,713 | 10,607 | 10,196 | 10,814 | 9,261 | 8,949 | 6,773 | Mar-22 | 10,814 |
| Lebanon | 32,496 | 33,700 | 28,050 | 25,052 | 27,437 | 31,747 | 31,456 | 32,346 | 28,146 | 26,468 | 23,581 | 27,220 | Aug-21 | 33,700 |
| Lincoln | 19,919 | 21,999 | 19,325 | 17,230 | 19,761 | 21,489 | 32,591 | 33,821 | 29,903 | 31,811 | 28,810 | 33,640 | Feb-22 | 33,821 |
| Lockhart | 11,148 | 11,467 | 12,870 | 17,234 | 19,817 | 22,608 | 21,804 | 24,261 | 21,131 | 20,041 | 17,947 | 13,233 | Feb-22 | 24,261 |
| Lyons | 17,342 | 18,189 | 17,645 | 18,602 | 20,462 | 20,284 | 20,886 | 20,990 | 21,022 | 19,645 | 17,632 | 17,422 | Mar-22 | 21,022 |
| Madras | 18,790 | 19,133 | 15,032 | 16,816 | 17,408 | 20,689 | 20,994 | 24,394 | 19,728 | 16,907 | 13,067 | 17,264 | Feb-22 | 24,394 |
| Mallory | 12,719 | 14,292 | 10,680 | 9,486 | 11,011 | 13,281 | 13,041 | 12,874 | 10,975 | 13,661 | 11,215 | 15,337 | Jun-22 | 15,337 |
| Marys River | 14,419 | 15,116 | 13,401 | 14,660 | 14,993 | 15,719 | 16,825 | 17,711 | 15,908 | 15,683 | 14,340 | 12,593 | Feb-22 | 17,711 |
| Medford | 25,056 | 24,762 | 20,349 | 15,402 | 17,071 | 18,076 | 2,153 | 10,225 | 8,446 | 7,497 | 7,404 | 12,386 | Jul-21 | 25,056 |
| Merlin | 22,950 | 23,280 | 18,845 | 22,016 | 25,346 | 25,475 | 16,284 | 16,584 | 16,173 | 15,924 | 16,037 | 16,177 | Dec-21 | 25,475 |
| Merrill | 9,336 | 7,772 | 7,269 | 4,831 | 4,603 | 5,585 | 26,279 | 26,554 | 25,793 | 21,617 | 24,550 | 31,570 | Jun-22 | 31,570 |
| Mile High | 10,581 | 9,794 | 8,931 | 10,775 | 11,586 | 12,262 | 30,201 | 31,577 | 27,090 | 26,417 | 19,987 | 19,310 | Feb-22 | 31,577 |
| Murder Creek | 50,524 | 54,318 | 50,109 | 46,199 | 45,780 | 49,460 | 8,749 | 5,878 | 5,008 | 8,652 | 10,721 | 9,097 | Aug-21 | 54,318 |
| Oak Knoll | 18,868 | 18,537 | 14,008 | 15,594 | 17,109 | 19,408 | 12,143 | 13,039 | 12,155 | 11,993 | 11,648 | 9,753 | Dec-21 | 19,408 |
| O'Brien | 1,413 | 1,331 | 1,099 | 1,483 | 1,584 | 1,641 | 49,504 | 47,673 | 46,617 | 46,805 | 65,816 | 63,946 | May-22 | 65,816 |
| REDACTED | 21,334 | 24,422 | 21,543 | 18,706 | 16,323 | 16,967 | 23,426 | 21,527 | 17,080 | 17,115 | 15,454 | 17,441 | Aug-21 | 24,422 |
| Overpass | 33,116 | 35,097 | 26,856 | 27,270 | 29,416 | 32,578 | 1,698 | 1,685 | 1,681 | 1,717 | 1,499 | 1,073 | Aug-21 | 35,097 |
| Pallette | 456 | 379 | 328 | 329 | 397 | 467 | 17,704 | 17,952 | 17,599 | 16,139 | 16,301 | 17,420 | Feb-22 | 17,952 |
| Park Street | 32,569 | 31,946 | 27,184 | 21,829 | 25,089 | 24,979 | 32,125 | 35,430 | 31,864 | 28,625 | 26,288 | 30,205 | Feb-22 | 35,430 |
| Parkrose | 27,150 | 30,026 | 23,442 | 20,511 | 23,062 | 27,343 | 581 | 490 | 448 | 389 | 298 | 269 | Aug-21 | 30,026 |
| Pendleton | 30,482 | 30,673 | 22,874 | 17,901 | 20,246 | 25,178 | 13,851 | 14,050 | 12,150 | 11,136 | 10,819 | 29,342 | Aug-21 | 30,673 |
| Pilot Butte | 17,907 | 19,051 | 14,598 | 11,731 | 12,971 | 16,529 | 25,634 | 26,176 | 22,561 | 23,926 | 22,151 | 26,806 | Jun-22 | 26,806 |
| Pilot Rock | 7,695 | 7,589 | - | - | 4,743 | 6,430 | 24,187 | 21,811 | 18,672 | 15,698 | 13,347 | 20,633 | Jan-22 | 24,187 |
| Prineville | 36,706 | 37,307 | 30,339 | 30,645 | 33,450 | 36,343 | 14,787 | 16,745 | 14,178 | 12,215 | 11,048 | 16,954 | Aug-21 | 37,307 |
| Prospect Central | 1,992 | 1,549 | 1,713 | 1,546 | 1,900 | 2,083 | 35,829 | 43,287 | 37,932 | 33,034 | 32,508 | 30,517 | Feb-22 | 43,287 |
| Queen Ave | 37,075 | 40,484 | 32,421 | 23,775 | 28,039 | 33,445 | 31,291 | 31,246 | 28,088 | 26,607 | 23,527 | 34,464 | Aug-21 | 40,484 |
| Redmond 115 | 37,848 | 39,811 | 31,386 | 31,285 | 38,334 | 39,600 | 36,831 | 44,159 | 38,372 | 33,310 | 29,932 | 35,430 | Feb-22 | 44,159 |
| Riddle | 16,485 | 16,162 | 13,979 | 14,523 | 16,446 | 17,070 | 19,115 | 21,412 | 16,988 | 16,471 | 14,125 | 15,337 | Feb-22 | 21,412 |
| REDACTED | 11,880 | 12,162 | 12,489 | 12,505 | 12,657 | 12,737 | 12,183 | 11,985 | 11,389 | 11,783 | 11,556 | 11,026 | Dec-21 | 12,737 |
| Roseburg | 22,343 | 23,596 | 19,756 | 15,868 | 19,284 | 19,605 | 21,357 | 23,365 | 19,823 | 19,560 | 16,235 | 21,780 | Aug-21 | 23,596 |
| Ross Ave | 7,529 | 7,547 | 6,551 | 5,105 | 5,542 | 6,604 | 6,462 | 6,680 | 5,846 | 5,552 | 5,137 | 6,078 | Aug-21 | 7,547 |
| Roxy Ann | 14,402 | 14,589 | 10,309 | 6,716 | 6,875 | 8,436 | 7,756 | 8,289 | 6,977 | 6,584 | 7,908 | 14,367 | Aug-21 | 14,589 |
| Russelville | 29,372 | 32,422 | 25,378 | 22,402 | 25,379 | 30,881 | 30,404 | 29,695 | 25,184 | 25,733 | 21,837 | 28,064 | Aug-21 | 32,422 |
| Sage Road | 30,866 | 30,196 | 25,865 | 20,722 | 23,491 | 25,041 | 24,194 | 24,970 | 24,426 | 21,542 | 22,755 | 28,151 | Jul-21 | 30,866 |
| Scenic | 29,184 | 27,959 | 22,479 | 17,727 | 20,272 | 21,119 | 22,514 | 22,689 | 19,945 | 18,490 | 17,647 | 25,915 | Jul-21 | 29,184 |
| Scio | 5,604 | 5,804 | 4,536 | 4,569 | 4,993 | 5,687 | 5,862 | 6,289 | 5,473 | 5,048 | 4,492 | 4,420 | Feb-22 | 6,289 |
| Seaside | 16,787 | 13,785 | 18,121 | 15,896 | 18,707 | 23,736 | 21,713 | 20,920 | 18,739 | 18,423 | 16,242 | 14,382 | Dec-21 | 23,736 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Shevlin Park | 22,189 | 22,985 | 16,096 | 13,807 | 14,721 | 20,205 | 17,983 | 18,813 | 17,564 | 23,366 | 13,670 | 20,564 | Apr-22 | 23,366 |
| Southgate | 14,378 | 14,153 | 13,083 | 11,508 | 13,110 | 15,319 | 14,368 | 14,958 | 13,479 | 13,773 | 11,619 | 14,560 | Dec-21 | 15,319 |
| State Street | 18,486 | 20,510 | 19,081 | 24,259 | 29,255 | 35,572 | 32,843 | 36,759 | 31,692 | 29,971 | 26,219 | 19,832 | Feb-22 | 36,759 |
| Stayton | 35,054 | 38,167 | 30,054 | 26,643 | 31,206 | 35,029 | 36,836 | 39,282 | 33,021 | 36,354 | 26,728 | 31,714 | Feb-22 | 39,282 |
| Stevens Road | 23,133 | 24,180 | 17,761 | 14,094 | 16,276 | 17,019 | 17,929 | 19,544 | 17,610 | 15,624 | 13,681 | 22,877 | Aug-21 | 24,180 |
| Sutherlin | 12,176 | 12,426 | 10,418 | 9,530 | 10,936 | 11,508 | 11,781 | 13,496 | 11,207 | 10,667 | 9,096 | 11,158 | Feb-22 | 13,496 |
| Sweet Home | 23,059 | 24,660 | 20,059 | 22,396 | 22,018 | 24,553 | 24,756 | 28,375 | 24,942 | 22,212 | 20,752 | 20,360 | Feb-22 | 28,375 |
| Takelma | 9,211 | 9,239 | 6,813 | 8,641 | 9,865 | 9,666 | 10,658 | 11,871 | 9,771 | 9,310 | 7,093 | 8,696 | Feb-22 | 11,871 |
| Talent | 18,577 | 18,623 | 14,091 | 14,997 | 17,452 | 18,119 | 19,294 | 20,861 | 17,329 | 15,973 | 13,790 | 17,791 | Feb-22 | 20,861 |
| Texum | 12,522 | 12,495 | 9,896 | 10,761 | 12,129 | 12,898 | 12,688 | 13,172 | 14,898 | 11,749 | 10,623 | 9,620 | Mar-22 | 14,898 |
| Umatilla | 15,286 | 14,457 | 12,568 | 12,990 | 9,862 | 12,061 | 13,104 | 11,883 | 9,821 | 8,930 | 9,403 | 13,604 | Jul-21 | 15,286 |
| Vernon | 30,176 | 34,718 | 23,861 | 21,161 | 23,670 | 27,899 | 28,389 | 27,496 | 23,287 | 23,315 | 20,747 | 30,527 | Aug-21 | 34,718 |
| Vilas Road | 20,867 | 20,391 | 18,118 | 13,380 | 14,603 | 15,624 | 16,129 | 16,429 | 14,761 | 14,054 | 16,091 | 20,746 | Jul-21 | 20,867 |
| Village Green | 13,306 | 14,752 | 11,265 | 11,528 | 12,715 | 13,795 | 13,935 | 15,158 | 13,241 | 12,830 | 11,325 | 13,082 | Feb-22 | 15,158 |
| Vine Street | 24,011 | 24,056 | 18,450 | 12,353 | 14,875 | 17,015 | 15,944 | 15,837 | 14,017 | 13,622 | 12,135 | 22,356 | Aug-21 | 24,056 |
| Warrenton | 15,946 | 17,755 | 16,158 | 17,162 | 18,131 | 19,041 | 18,895 | 19,915 | 18,615 | 18,025 | 16,525 | 16,471 | Feb-22 | 19,915 |
| Weston | 10,016 | 10,427 | 10,047 | 9,552 | 9,251 | 6,132 | 4,112 | 6,255 | 7,134 | 7,223 | 5,735 | 9,942 | Aug-21 | 10,427 |
| Westside | 13,639 | 13,701 | 11,281 | 11,516 | 12,383 | 13,269 | 13,344 | 14,785 | 12,102 | 15,371 | 12,917 | 13,040 | Apr-22 | 15,371 |
| White City | 42,946 | 41,313 | 38,196 | 35,992 | 35,932 | 38,487 | 37,844 | 39,982 | 36,050 | 35,087 | 34,157 | 38,632 | Jul-21 | 42,946 |
| Winchester | 24,879 | 25,043 | 20,020 | 17,214 | 18,869 | 19,831 | 21,071 | 22,922 | 19,773 | 19,166 | 16,169 | 24,155 | Aug-21 | 25,043 |
| Yew Ave | 18,447 | 20,556 | 15,152 | 13,923 | 15,257 | 18,813 | 17,293 | 19,442 | 17,347 | 14,217 | 12,878 | 16,939 | | |
| | | | | | | | | | | | | | Total | |
| Substation Peaks | 424,997 | 1,089,883 | 11,974 | - | 968 | 140,512 | 33,210 | 741,399 | 71,134 | 72,256 | 65,816 | 101,349 | 2,753,497 | |
| Weighting Factor | 15.43% | 39.58% | 0.43% | 0.00% | 0.04% | 5.10% | 1.21% | 26.93% | 2.58% | 2.62% | 2.39% | 3.68% | 100.00% | |

PacifiCorp
Oregon Marginal Cost Study
Distribution Substations Monthly Peaks - kW
12 months ended June 2023

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Substation | | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | Jan-23 | Feb-23 | Mar-23 | Apr-23 | May-23 | Jun-23 | Peak Month | Peak Load |
| Agness Avenue | | 18,785 | 18,462 | 17,408 | 16,998 | 16,045 | 15,944 | 16,763 | 17,324 | 15,859 | 14,975 | 14,426 | 15,662 | Jul-22 | 18,785 |
| Albina | | 24,040 | 24,888 | 23,075 | 21,291 | 21,444 | 21,805 | 20,306 | 20,104 | 23,215 | 22,032 | 22,053 | 21,687 | Aug-22 | 24,888 |
| Alderwood | | 24,996 | 24,982 | 22,062 | 20,659 | 19,851 | 24,665 | 19,653 | 19,684 | 19,287 | 19,509 | 23,516 | 22,303 | Jul-22 | 24,996 |
| Applegate | | 11,277 | 10,563 | 9,724 | 9,233 | 11,506 | 12,097 | 13,503 | 13,051 | 11,444 | 11,015 | 7,928 | 9,113 | Jan-23 | 13,503 |
| Ashland | | 18,576 | 16,190 | 15,888 | 12,113 | 14,122 | 16,151 | 16,089 | 16,021 | 14,700 | 14,051 | 11,874 | 14,518 | Jul-22 | 18,576 |
| Bandon | | 2,018 | 1,792 | 1,975 | 2,133 | 2,359 | 2,761 | 2,674 | 2,848 | 2,933 | 3,187 | 2,004 | 2,107 | Apr-23 | 3,187 |
| Beall Lane | | 21,179 | 18,635 | 25,016 | 17,994 | 15,427 | 15,939 | 16,793 | 16,444 | 15,351 | 14,872 | 15,989 | 17,670 | Sep-22 | 25,016 |
| Belknap | | 31,678 | 29,123 | 28,805 | 21,738 | 21,411 | 23,094 | 23,130 | 23,082 | 25,150 | 23,960 | 27,570 | 26,791 | Jul-22 | 31,678 |
| Bend Plant | | 20,587 | 17,689 | 17,881 | 15,558 | 15,312 | 15,483 | 16,783 | 16,351 | 13,799 | 12,658 | 10,853 | 15,358 | Jul-22 | 20,587 |
| Bloss | | 11,376 | 9,650 | 11,707 | 10,175 | 2,653 | 1,242 | 840 | 597 | 628 | 543 | 444 | 335 | Sep-22 | 11,707 |
| Bly | | 2,011 | 2,216 | 1,862 | 2,523 | 1,193 | 1,518 | 1,371 | 1,263 | 1,638 | 1,566 | 1,188 | 2,035 | Oct-22 | 2,523 |
| REDACTED | | 890 | 1,032 | 1,062 | 913 | 1,013 | 961 | 907 | 940 | 915 | 935 | 969 | 897 | Sep-22 | 1,062 |
| Bond Street | | 20,857 | 17,833 | 17,137 | 13,196 | 16,789 | 20,062 | 20,373 | 17,517 | 15,098 | 13,679 | 11,551 | 15,567 | Jul-22 | 20,857 |
| Brookhurst | | 41,502 | 36,525 | 37,254 | 23,485 | 24,579 | 27,497 | 29,514 | 27,543 | 29,220 | 28,260 | 33,034 | 33,973 | Jul-22 | 41,502 |
| Bryant | | 27,601 | 24,708 | 25,566 | 16,935 | 20,753 | 23,694 | 22,835 | 21,087 | 21,167 | 19,400 | 18,371 | 22,085 | Jul-22 | 27,601 |
| Buchanan | | 28,363 | 26,954 | 21,947 | 19,334 | 27,454 | 27,170 | 26,262 | 26,091 | 23,953 | 21,804 | 16,828 | 20,345 | Jul-22 | 28,363 |
| Buckaroo | | 16,783 | 16,819 | 15,498 | 11,866 | 13,243 | 13,824 | 13,359 | 13,731 | 12,904 | 12,722 | 17,000 | 15,014 | May-23 | 17,000 |
| Calapooya | | 6,320 | 5,764 | 5,391 | 4,697 | 5,329 | 5,877 | 5,731 | 5,835 | 5,466 | 5,131 | 4,977 | 5,156 | Jul-22 | 6,320 |
| Campbell | | 19,320 | 19,012 | 17,985 | 13,259 | 12,827 | 16,829 | 16,974 | 16,313 | 15,438 | 14,768 | 17,202 | 20,447 | Jun-23 | 20,447 |
| Cannon Beach | | 4,736 | 4,147 | 4,395 | 4,847 | 6,517 | 7,890 | 7,437 | 8,454 | 9,701 | 6,677 | 4,727 | 4,207 | Mar-23 | 9,701 |
| Canyonville | | 7,828 | 7,280 | 7,180 | 6,168 | 8,129 | 8,094 | 8,555 | 8,259 | 6,313 | 5,951 | 5,557 | 6,066 | Jan-23 | 8,555 |
| Casebeer | | 8,157 | 7,039 | 7,316 | 3,338 | 3,038 | 3,771 | 3,690 | 3,258 | 3,355 | 3,152 | 7,053 | 6,890 | Jul-22 | 8,157 |
| Cave Junction | | 14,233 | 13,151 | 12,681 | 13,795 | 16,011 | 16,843 | 17,598 | 17,941 | 18,845 | 16,093 | 12,187 | 11,954 | Mar-23 | 18,845 |
| Caveman | | 22,149 | 20,291 | 18,779 | 13,931 | 14,607 | 15,919 | 16,398 | 16,310 | 14,431 | 13,129 | 15,154 | 17,622 | Jul-22 | 22,149 |
| Cherry Lane | | 7,364 | 8,300 | 7,335 | 7,167 | 7,630 | 7,368 | 7,438 | 7,724 | 7,511 | 7,497 | 7,227 | 7,328 | Aug-22 | 8,300 |
| Chiloquin | | 7,671 | 7,746 | 7,840 | 7,776 | 7,267 | 6,138 | 7,566 | 7,158 | 7,063 | 6,854 | 7,236 | 7,894 | Jun-23 | 7,894 |
| China Hat | | 22,331 | 19,414 | 18,557 | 16,405 | 22,372 | 26,276 | 29,231 | 25,346 | 22,555 | 20,131 | 15,631 | 16,687 | Jan-23 | 29,231 |
| Circle Blvd | | 17,178 | 17,348 | 15,451 | 15,105 | 14,290 | 14,279 | 14,306 | 13,891 | 14,929 | 14,529 | 15,406 | 15,661 | Aug-22 | 17,348 |
| Cleveland Ave. | | 36,641 | 33,636 | 32,822 | 25,750 | 32,884 | 36,251 | 47,582 | 34,434 | 30,204 | 28,882 | 24,975 | 29,716 | Jan-23 | 47,582 |
| Cloake | | 16,934 | 16,380 | 13,536 | 9,463 | 11,556 | 11,149 | 13,267 | 12,534 | 11,232 | 10,329 | 12,475 | 13,860 | Jul-22 | 16,934 |
| Coburg | | 2,721 | 2,380 | 2,158 | 1,604 | 2,135 | 2,360 | 2,320 | 2,234 | 2,037 | 1,840 | 2,285 | 2,283 | Jul-22 | 2,721 |
| Columbia | | 33,275 | 32,405 | 29,549 | 24,564 | 27,789 | 31,906 | 29,890 | 28,636 | 28,910 | 26,764 | 29,128 | 29,471 | Jul-22 | 33,275 |
| Coquille | | 10,110 | 11,561 | 10,885 | 12,511 | 16,280 | 16,403 | 18,115 | 17,743 | 16,404 | 15,953 | 12,650 | 11,258 | Jan-23 | 18,115 |
| Crowfoot | | 16,172 | 15,051 | 849 | 8,725 | 15,112 | 16,061 | 4 | 12 | 14,428 | 13,206 | 13,709 | 14,086 | Jul-22 | 16,172 |
| Cully | | 10,789 | 10,550 | 8,562 | 7,593 | 8,415 | 10,706 | 9,465 | 9,726 | 8,381 | 9,565 | 8,869 | 10,078 | Jul-22 | 10,789 |
| Culver | | 7,124 | 6,806 | 6,286 | 5,584 | 7,827 | 9,043 | 10,218 | 9,020 | 7,805 | 6,991 | 5,000 | 6,297 | Jan-23 | 10,218 |
| Dairy | | 9,654 | 8,504 | 8,167 | 3,441 | 2,475 | 3,000 | 2,678 | 2,403 | 2,643 | 3,134 | 8,017 | 7,074 | Jul-22 | 9,654 |
| Dallas | | 38,003 | 35,121 | 30,209 | 25,844 | 32,029 | 39,422 | 37,129 | 37,679 | 35,364 | 30,789 | 29,918 | 29,492 | Dec-22 | 39,422 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Dalreed | 51,656 | 48,796 | 42,829 | 21,993 | 7,905 | 8,069 | 7,685 | 7,882 | 17,789 | 25,026 | 36,279 | 49,283 | Jul-22 | 51,656 |
| Deschutes | 8,571 | 7,880 | 7,976 | 7,923 | 12,591 | 13,902 | 16,472 | 14,095 | 10,875 | 10,330 | 6,634 | 7,307 | Jan-23 | 16,472 |
| Devils Lake | 19,596 | 18,941 | 19,345 | 23,842 | 30,496 | 36,731 | 34,978 | 35,247 | 32,075 | 30,060 | 21,348 | 19,325 | Dec-22 | 36,731 |
| Dixon | 3,642 | 3,506 | 3,156 | 2,519 | 2,500 | 2,823 | 2,625 | 2,777 | 2,543 | 2,726 | 3,034 | 3,238 | Jul-22 | 3,642 |
| Dodge Bridge | 12,416 | 11,080 | 11,199 | 9,058 | 11,142 | 12,939 | 13,686 | 12,755 | 11,532 | 10,533 | 7,930 | 16,080 | Jun-23 | 16,080 |
| Dowell | 17,743 | 16,457 | 14,884 | 10,337 | 12,487 | 12,894 | 14,219 | 14,030 | 12,028 | 11,285 | 12,747 | 14,740 | Jul-22 | 17,743 |
| Easy Valley | 21,810 | 19,990 | 17,872 | 11,505 | 16,185 | 16,836 | 19,079 | 18,712 | 16,042 | 14,920 | 14,329 | 17,439 | Jul-22 | 21,810 |
| Empire | 9,145 | 8,669 | 9,902 | 13,485 | 17,722 | 19,340 | 21,664 | 20,529 | 20,618 | 18,165 | 12,780 | 10,648 | Jan-23 | 21,664 |
| Fern Hill | 1,221 | 1,160 | 2,644 | 1,845 | 2,609 | 3,477 | 4,085 | 4,255 | 3,724 | 3,257 | 2,451 | 1,929 | Feb-23 | 4,255 |
| Fielder Creek | 12,037 | 11,317 | 10,625 | 9,499 | 11,415 | 12,279 | 13,037 | 12,404 | 11,066 | 11,034 | 7,878 | 9,315 | Jan-23 | 13,037 |
| Foothills Rd | 15,511 | 14,090 | 14,061 | 10,146 | 10,275 | 11,062 | 11,275 | 10,906 | 10,498 | 10,375 | 11,590 | 13,472 | Jul-22 | 15,511 |
| Garden Valley | 15,399 | 14,822 | 12,666 | 9,765 | 10,262 | 10,335 | 11,351 | 10,862 | 10,147 | 10,937 | 11,750 | 12,676 | Jul-22 | 15,399 |
| Glendale | 10,567 | 10,241 | 9,296 | 10,256 | 12,563 | 12,927 | 13,887 | 13,276 | 12,703 | 38,302 | 34,196 | 16,884 | Apr-23 | 38,302 |
| Gold Hill | 8,809 | 8,100 | 7,928 | 5,885 | 7,937 | 8,647 | 9,192 | 8,786 | 7,978 | 7,647 | 5,912 | 7,130 | Jan-23 | 9,192 |
| Gordon Hollow | 4,960 | 4,509 | 4,025 | 3,063 | 4,991 | 6,264 | 5,586 | 5,404 | 4,344 | 3,699 | 3,264 | 3,613 | Dec-22 | 6,264 |
| Goshen | 6,205 | 6,056 | 5,291 | 4,707 | 6,815 | 6,661 | 7,444 | 7,027 | 6,233 | 5,742 | 5,360 | 5,497 | Jan-23 | 7,444 |
| Grant Street | 27,857 | 25,798 | 22,295 | 21,147 | 30,354 | 29,174 | 29,102 | 29,578 | 26,646 | 25,787 | 26,742 | 26,317 | Nov-22 | 30,354 |
| Green | 15,267 | 14,903 | 13,194 | 10,088 | 12,880 | 13,795 | 16,430 | 15,272 | 13,754 | 12,471 | 12,028 | 12,282 | Jan-23 | 16,430 |
| Harrisburg | 8,341 | 7,802 | 6,944 | 6,644 | 8,549 | 8,449 | 8,871 | 9,266 | 8,371 | 7,629 | 6,744 | 6,796 | Feb-23 | 9,266 |
| Hazelwood | 7,088 | 6,449 | 5,646 | 5,601 | 6,591 | 7,439 | 6,886 | 7,298 | 6,288 | 6,114 | 6,113 | 6,281 | Dec-22 | 7,439 |
| Hillview | 30,695 | 27,283 | 25,916 | 19,542 | 29,205 | 30,433 | 25,856 | 25,390 | 25,697 | 27,619 | 24,861 | 24,589 | Jul-22 | 30,695 |
| Holladay | 22,204 | 22,702 | 18,844 | 18,287 | 19,358 | 20,104 | 18,412 | 17,641 | 22,908 | 16,634 | 18,769 | 18,236 | Mar-23 | 22,908 |
| Hollywood | 34,318 | 33,094 | 27,468 | 22,625 | 24,065 | 31,979 | 25,969 | 26,838 | 24,708 | 23,064 | 27,994 | 26,534 | Jul-22 | 34,318 |
| Hood River | 32,591 | 31,720 | 27,652 | 18,819 | 27,677 | 36,282 | 33,046 | 31,055 | 26,377 | 23,791 | 24,328 | 25,351 | Dec-22 | 36,282 |
| Hornet | 16,610 | 15,353 | 14,978 | 10,672 | 12,187 | 14,458 | 14,290 | 13,204 | 13,108 | 11,948 | 11,561 | 13,284 | Jul-22 | 16,610 |
| Independence | 21,493 | 20,168 | 17,477 | 13,158 | 16,925 | 20,364 | 19,093 | 20,077 | 17,485 | 15,672 | 16,171 | 17,618 | Jul-22 | 21,493 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jacksonville | 19,725 | 16,724 | 16,433 | 9,959 | 13,667 | 15,871 | 16,660 | 15,291 | 15,149 | 13,533 | 12,165 | 15,347 | Jul-22 | 19,725 |
| Jefferson | 15,508 | 13,702 | 12,205 | 10,387 | 16,122 | 16,245 | 17,836 | 18,794 | 19,182 | 14,407 | 10,584 | 12,390 | Mar-23 | 19,182 |
| Jerome Prairie | 8,635 | 8,208 | 7,493 | 6,751 | 8,656 | 9,241 | 9,625 | 9,629 | 8,644 | 7,625 | 7,117 | 7,312 | Feb-23 | 9,629 |
| Junction City | 18,869 | 18,396 | 15,553 | 13,657 | 15,822 | 18,517 | 17,176 | 16,814 | 15,898 | 14,508 | 12,011 | 8,895 | Jul-22 | 18,869 |
| Killingsworth | 21,233 | 21,183 | 18,472 | 19,941 | 24,599 | 31,125 | 26,406 | 22,371 | 20,966 | 19,227 | 20,723 | 22,399 | Dec-22 | 31,125 |
| Knappa Svensen | 3,032 | 3,262 | 2,823 | 3,519 | 4,723 | 6,073 | 5,500 | 5,423 | 5,228 | 4,467 | 3,297 | 2,879 | Dec-22 | 6,073 |
| Knott | 30,237 | 29,181 | 26,022 | 21,193 | 25,881 | 33,498 | 28,024 | 28,334 | 24,974 | 23,416 | 26,373 | 24,914 | Dec-22 | 33,498 |
| Lakeport | 17,718 | 17,217 | 16,916 | 16,405 | 18,266 | 18,905 | 18,942 | 18,808 | 18,769 | 18,246 | 17,261 | 16,042 | Jan-23 | 18,942 |
| Lancaster | 7,867 | 8,071 | 7,742 | 7,613 | 9,102 | 9,703 | 11,629 | 12,543 | 11,620 | 9,385 | 7,806 | 7,915 | Feb-23 | 12,543 |
| Lebanon | 33,372 | 31,750 | 29,487 | 24,072 | 30,502 | 32,276 | 33,026 | 31,804 | 28,244 | 27,408 | 27,193 | 28,569 | Jul-22 | 33,372 |
| Lincoln | 36,562 | 34,488 | 32,745 | 29,677 | 32,070 | 37,609 | 35,015 | 35,193 | 32,443 | 30,947 | 33,276 | 31,490 | Dec-22 | 37,609 |
| Lockhart | 11,710 | 12,541 | 12,215 | 17,226 | 20,592 | 22,990 | 23,690 | 23,241 | 22,636 | 20,974 | 14,874 | 12,323 | Jan-23 | 23,690 |
| Lyons | 18,373 | 17,369 | 15,720 | 16,344 | 20,080 | 20,992 | 21,704 | 20,911 | 21,578 | 20,003 | 16,855 | 16,906 | Jan-23 | 21,704 |
| Madras | 19,892 | 21,721 | 17,335 | 14,343 | 19,277 | 24,248 | 24,647 | 22,649 | 18,946 | 17,693 | 15,079 | 17,256 | Jan-23 | 24,647 |
| Mallory | 16,550 | 13,392 | 11,509 | 9,531 | 11,317 | 15,502 | 12,570 | 13,589 | 18,001 | 10,148 | 12,040 | 11,099 | Mar-23 | 18,001 |
| Marys River | 16,446 | 16,661 | 15,018 | 14,589 | 16,844 | 17,319 | 17,193 | 17,155 | 16,012 | 15,302 | 13,920 | 14,207 | Dec-22 | 17,319 |
| Medford | 14,530 | 13,502 | 12,415 | 8,077 | 8,793 | 11,520 | 10,291 | 9,442 | 8,110 | 7,703 | 11,240 | 11,586 | Jul-22 | 14,530 |
| Merlin | 15,258 | 15,731 | 16,407 | 15,759 | 15,668 | 16,017 | 16,374 | 16,655 | 16,468 | 16,700 | 16,880 | 16,340 | May-23 | 16,880 |
| Merrill | 42,742 | 35,754 | 35,470 | 26,309 | 24,706 | 27,552 | 28,480 | 36,310 | 25,400 | 15,761 | 34,776 | 34,495 | Jul-22 | 42,742 |
| Mile High | 25,077 | 22,360 | 19,123 | 18,192 | 27,259 | 29,617 | 31,397 | 32,594 | 25,963 | 24,615 | 17,065 | 18,896 | Feb-23 | 32,594 |
| Murder Creek | 16,228 | 13,931 | 7,488 | 4,265 | 5,191 | 5,931 | 5,896 | 5,457 | 12,100 | 4,960 | 7,927 | 7,669 | Jul-22 | 16,228 |
| Oak Knoll | 10,482 | 10,398 | 10,056 | 16,472 | 22,210 | 13,554 | 13,920 | 12,980 | 12,407 | 11,904 | 11,060 | 9,719 | Nov-22 | 22,210 |
| O'Brien | 54,674 | 49,646 | 48,572 | 40,225 | 45,618 | 53,030 | 50,009 | 52,768 | 49,438 | 47,776 | 54,121 | 51,583 | Jul-22 | 54,674 |
| REDACTED | 22,277 | 18,861 | 18,285 | 14,549 | 17,295 | 19,828 | 19,766 | 19,939 | 18,307 | 17,904 | 13,245 | 16,758 | Jul-22 | 22,277 |
| Overpass | 1,368 | 1,274 | 1,183 | 1,326 | 1,450 | 1,509 | 1,616 | 1,550 | 1,939 | 1,432 | 1,192 | 1,083 | Mar-23 | 1,939 |
| Pallette | 22,738 | 24,994 | 23,116 | 18,303 | 18,028 | 19,408 | 20,024 | 21,739 | 20,611 | 20,768 | 21,974 | 23,555 | Aug-22 | 24,994 |
| Park Street | 34,430 | 32,681 | 30,947 | 27,012 | 32,308 | 37,148 | 37,616 | 35,810 | 31,797 | 30,885 | 25,438 | 27,908 | Jan-23 | 37,616 |
| Parkrose | 445 | 395 | 359 | 314 | 467 | 523 | 566 | 441 | 401 | 375 | 249 | 266 | Jan-23 | 566 |
| Pendleton | 36,454 | 34,126 | 30,999 | 24,178 | 26,003 | 27,990 | 28,856 | 29,566 | 25,520 | 23,233 | 26,702 | 30,543 | Jul-22 | 36,454 |
| Pilot Butte | 29,372 | 28,588 | 24,303 | 19,322 | 23,863 | 31,012 | 25,501 | 26,646 | 23,312 | 23,776 | 26,637 | 24,830 | Dec-22 | 31,012 |
| Pilot Rock | 25,680 | 23,200 | 20,487 | 12,804 | 17,716 | 22,469 | 19,814 | 18,978 | 16,144 | 15,545 | 17,759 | 18,931 | Jul-22 | 25,680 |
| Prineville | 20,304 | 17,656 | 17,884 | 11,188 | 15,559 | 18,602 | 18,418 | 17,362 | 14,030 | 12,980 | 12,756 | 16,309 | Jul-22 | 20,304 |
| Prospect Central | 40,072 | 36,793 | 33,644 | 29,534 | 36,887 | 42,643 | 46,154 | 40,587 | 37,951 | 36,131 | 26,752 | 32,894 | Jan-23 | 46,154 |
| Queen Ave | 40,648 | 39,467 | 34,302 | 26,809 | 30,302 | 36,555 | 30,569 | 37,061 | 29,138 | 27,295 | 33,061 | 34,905 | Jul-22 | 40,648 |
| Redmond 115 | 40,947 | 38,889 | 36,451 | 30,461 | 37,438 | 45,869 | 47,432 | 42,045 | 36,988 | 34,694 | 29,230 | 33,678 | Jan-23 | 47,432 |
| Riddle | 16,887 | 16,585 | 14,357 | 14,195 | 18,534 | 19,404 | 20,780 | 19,746 | 17,795 | 16,940 | 13,467 | 13,221 | Jan-23 | 20,780 |
| REDACTED | 10,020 | 10,445 | 10,708 | 11,414 | 12,182 | 10,984 | 11,023 | 11,268 | 11,812 | 11,437 | 10,942 | 10,985 | Nov-22 | 12,182 |
| Roseburg | 23,381 | 23,259 | 19,737 | 15,900 | 23,519 | 21,820 | 23,635 | 22,172 | 23,145 | 19,855 | 18,550 | 19,516 | Jan-23 | 23,635 |
| Ross Ave | 7,667 | 6,860 | 7,366 | 4,780 | 6,018 | 6,622 | 6,539 | 6,214 | 5,935 | 5,497 | 4,738 | 5,503 | Jul-22 | 7,667 |
| Roxy Ann | 17,350 | 14,684 | 14,792 | 8,654 | 7,159 | 8,036 | 8,383 | 8,016 | 7,427 | 9,037 | 10,854 | 13,617 | Jul-22 | 17,350 |
| Russelville | 31,401 | 30,606 | 26,167 | 17,926 | 21,969 | 30,494 | 29,518 | 32,272 | 27,618 | 24,467 | 25,835 | 24,800 | Feb-23 | 32,272 |
| Sage Road | 32,880 | 30,877 | 29,664 | 24,221 | 23,328 | 25,485 | 25,077 | 25,369 | 25,593 | 30,973 | 24,950 | 28,514 | Jul-22 | 32,880 |
| Scenic | 31,922 | 28,345 | 29,249 | 19,187 | 20,509 | 22,699 | 23,241 | 22,730 | 20,990 | 19,743 | 23,324 | 27,221 | Jul-22 | 31,922 |
| Scio | 5,381 | 5,179 | 4,597 | 4,251 | 5,855 | 6,175 | 6,349 | 6,207 | 5,322 | 4,808 | 4,114 | 4,720 | Jan-23 | 6,349 |
| Seaside | 14,450 | 13,804 | 13,599 | 15,392 | 19,789 | 23,199 | 26,205 | 22,546 | 20,333 | 19,620 | 14,798 | 13,328 | Jan-23 | 26,205 |
| Shevlin Park | 26,337 | 21,068 | 21,501 | 13,972 | 18,156 | 21,639 | 20,319 | 22,307 | 18,623 | 16,809 | 19,538 | 20,940 | Jul-22 | 26,337 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Southgate | 17,007 | 15,397 | 12,417 | 11,318 | 14,747 | 14,493 | 16,784 | 16,323 | 14,313 | 14,073 | 13,269 | 13,184 | Jul-22 | 17,007 |
| State Street | 17,724 | 18,092 | 18,404 | 23,216 | 30,983 | 33,736 | 38,294 | 36,058 | 35,908 | 33,375 | 23,596 | 19,142 | Jan-23 | 38,294 |
| Stayton | 37,459 | 34,909 | 30,806 | 24,694 | 35,037 | 36,960 | 38,340 | 38,123 | 32,015 | 29,573 | 29,021 | 30,981 | Jan-23 | 38,340 |
| Stevens Road | 25,904 | 24,719 | 23,399 | 14,597 | 18,720 | 21,108 | 21,197 | 20,729 | 19,209 | 16,779 | 17,128 | 20,409 | Jul-22 | 25,904 |
| Sutherlin | 12,531 | 12,016 | 10,545 | 8,774 | 12,028 | 11,457 | 14,037 | 12,843 | 11,931 | 10,843 | 10,194 | 10,583 | Jan-23 | 14,037 |
| Sweet Home | 25,517 | 23,946 | 21,514 | 20,520 | 26,795 | 27,192 | 30,122 | 28,850 | 25,792 | 21,503 | 16,655 | 21,264 | Jan-23 | 30,122 |
| Takelma | 10,077 | 8,876 | 9,123 | 7,682 | 10,546 | 11,919 | 12,406 | 11,351 | 10,061 | 9,827 | 6,400 | 8,039 | Jan-23 | 12,406 |
| Talent | 22,034 | 19,413 | 19,355 | 13,919 | 18,259 | 20,560 | 21,593 | 20,726 | 19,917 | 17,915 | 14,416 | 18,208 | Jul-22 | 22,034 |
| Texum | 12,553 | 12,250 | 11,611 | 11,055 | 12,399 | 14,322 | 14,093 | 13,092 | 13,095 | 11,970 | 9,849 | 9,599 | Dec-22 | 14,322 |
| Umatilla | 15,094 | 14,294 | 13,519 | 10,764 | 10,069 | 13,650 | 12,328 | 12,469 | 9,882 | 9,439 | 11,228 | 13,332 | Jul-22 | 15,094 |
| Vernon | 34,749 | 33,229 | 26,014 | 22,071 | 26,307 | 35,015 | 29,697 | 30,782 | 33,544 | 22,202 | 27,694 | 28,167 | Dec-22 | 35,015 |
| Vilas Road | 22,891 | 21,197 | 20,666 | 15,733 | 15,227 | 16,609 | 16,623 | 16,320 | 15,528 | 15,144 | 17,128 | 19,478 | Jul-22 | 22,891 |
| Village Green | 14,244 | 13,463 | 11,731 | 10,849 | 13,961 | 14,877 | 15,470 | 14,797 | 13,143 | 9,657 | 10,845 | 11,175 | Jan-23 | 15,470 |
| Vine Street | 25,841 | 23,693 | 19,528 | 15,497 | 16,074 | 19,056 | 16,315 | 16,716 | 15,208 | 18,406 | 19,817 | 18,521 | Jul-22 | 25,841 |
| Warrenton | 16,358 | 17,397 | 16,428 | 16,365 | 19,101 | 19,936 | 20,331 | 20,461 | 19,683 | 19,301 | 17,038 | 16,453 | Feb-23 | 20,461 |
| Weston | 10,649 | 11,102 | 10,321 | 9,044 | 6,218 | 4,209 | 6,604 | 6,202 | 6,064 | 5,643 | 5,032 | 8,757 | Aug-22 | 11,102 |
| Westside | 19,081 | 13,817 | 14,007 | 12,464 | 13,805 | 14,684 | 14,785 | 14,092 | 14,109 | 13,746 | 10,554 | 10,798 | Jul-22 | 19,081 |
| White City | 43,236 | 43,331 | 40,176 | 35,398 | 40,019 | 47,348 | 36,286 | 38,090 | 36,821 | 34,881 | 36,907 | 37,061 | Dec-22 | 47,348 |
| Winchester | 26,087 | 25,183 | 21,263 | 15,345 | 20,208 | 20,658 | 23,776 | 22,361 | 20,652 | 18,885 | 19,793 | 21,199 | Jul-22 | 26,087 |
| Yew Ave | 20,688 | 19,061 | 17,621 | 13,067 | 17,082 | 21,178 | 21,620 | 19,589 | 15,886 | 15,372 | 13,847 | 16,861 | Jan-23 | 21,620 |
| | | | | | | | | | | | | | Total | |
| Substation Peaks | 1,223,592 | 86,632 | 37,785 | 2,523 | 64,746 | 379,458 | 679,454 | 121,021 | 90,575 | 41,489 | 33,880 | 44,420 | 2,805,575 | |
| Weighting Factor | 43.61% | 3.09% | 1.35% | 0.09% | 2.31% | 13.53% | 24.22% | 4.31% | 3.23% | 1.48% | 1.21% | 1.58% | 100.00% | |
| | | | | | | | | | | | | | | |
| Three-Year Average | | | | | | | | | | | | | | |
| Weighting Factor | 21.19% | 15.81% | 1.36% | 0.28% | 1.62% | 8.08% | 10.89% | 11.52% | 2.71% | 1.56% | 1.20% | 23.78% | 100.00% | |

Uncollectables

PacifiCorp
Oregon Marginal Cost Study
Allocation of Uncollectible Expense between Members of Class
12 Months Ended December 2025

| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Percent of Total Revenues | | | | Allocated Net Uncollectible | | | | |
| Line | Description | Del. Volt | Residential | Commercial | Industrial | Irrigation | Residential | Commercial | Industrial | Irrigation | Total |
| 1 | Res - Sch 4 | (sec) | 100.00% | 0.00% | 0.00% | 0.00% | 7,450,315 | - | - | - | 7,450,315 |
| 2 | | | | | | | | | | | |
| 3 | GS - Sch 23 | (sec) | 0.00% | 21.78% | 1.86% | 0.00% | - | 190,826 | 295 | - | 191,120 |
| 4 | GS - Sch 23 | (pri) | 0.00% | 0.03% | 0.03% | 0.00% | - | 236 | 4 | - | 241 |
| 5 | GS - Sch 23 | Total | 0.00% | 21.81% | 1.89% | 0.00% | - | 191,062 | 299 | - | 191,361 |
| 6 | | | | | | | | | | | |
| 7 | GS - Sch 28 | (sec) | 0.00% | 27.99% | 5.81% | 0.00% | - | 245,234 | 919 | - | 246,153 |
| 8 | GS - Sch 28 | (pri) | 0.00% | 0.19% | 0.39% | 0.00% | - | 1,674 | 62 | - | 1,736 |
| 9 | GS - Sch 28 | Total | 0.00% | 28.18% | 6.20% | 0.00% | - | 246,908 | 981 | - | 247,890 |
| 10 | | | | | | | | | | | |
| 11 | GS - Sch 30 | (sec) | 0.00% | 13.34% | 12.52% | 0.00% | - | 116,881 | 1,980 | - | 118,861 |
| 12 | GS - Sch 30 | (pri) | 0.00% | 0.77% | 1.08% | 0.00% | - | 6,758 | 170 | - | 6,928 |
| 13 | GS - Sch 30 | Total | 0.00% | 14.11% | 13.59% | 0.00% | - | 123,639 | 2,150 | - | 125,789 |
| 14 | | | | | | | | | | | |
| 15 | LPS - Sch 48 | (sec) | 0.00% | 4.03% | 18.19% | 0.00% | - | 35,352 | 2,879 | - | 38,231 |
| 16 | LPS - Sch 48 | (pri) | 0.00% | 13.25% | 58.61% | 0.00% | - | 116,122 | 9,273 | - | 125,396 |
| 17 | LPS - Sch 48 | (trn) | 0.00% | 18.62% | 1.51% | 0.00% | - | 163,113 | 239 | - | 163,352 |
| 18 | LPS - Sch 48 | Total | 0.00% | 35.90% | 78.32% | 0.00% | - | 314,588 | 12,391 | - | 326,979 |
| 19 | | | | | | | | | | | |
| 20 | Irg - Sch 41 | (sec) | 0.00% | 0.00% | 0.00% | 100.00% | - | - | - | 125,324 | 125,324 |
| 21 | | | | | | | | | | | |
| 22 | Total | | | | | | 7,450,315 | 876,197 | 15,821 | 125,324 | 8,467,658 |

| 12 Months Ended June 2023 Net Write-offs | |
|---|---|
| Residential | $7,450,315 |
| Commercial | $876,197 |
| Industrial | $15,821 |
| Irrigation | $125,324 |
| Total | 8,467,658 |

Revenues

PacifiCorp
Oregon Marginal Cost Study
Revenues
12 Months Ended December 2025

| Line | Description | (A) Del. Volt | (B) Residential | (C) Commercial | (D) Industrial | (E) Irrigation | (F) PS&H | (G) Total |
|---|---|---|---|---|---|---|---|---|
| 1 | Res - Sch 4 | (sec) | 786,075,316 | - | - | - | - | 786,075,316 |
| 2 | | | | | | | | |
| 3 | GS - Sch 23 | (sec) | - | 157,321,246 | 2,335,114 | - | - | 159,656,360 |
| 4 | GS - Sch 23 | (pri) | - | 194,939 | 35,504 | - | - | 230,443 |
| 5 | GS - Sch 23 | Total | - | 157,516,185 | 2,370,618 | - | - | 159,886,803 |
| 6 | | | | | | | | |
| 7 | GS - Sch 28 | (sec) | - | 202,177,015 | 7,283,467 | - | - | 209,460,482 |
| 8 | GS - Sch 28 | (pri) | - | 1,380,206 | 493,630 | - | - | 1,873,836 |
| 9 | GS - Sch 28 | Total | - | 203,557,221 | 7,777,097 | - | - | 211,334,318 |
| 10 | | | | | | | | |
| 11 | GS - Sch 30 | (sec) | - | 96,359,540 | 15,693,758 | - | - | 112,053,298 |
| 12 | GS - Sch 30 | (pri) | - | 5,571,208 | 1,348,365 | - | - | 6,919,573 |
| 13 | GS - Sch 30 | Total | - | 101,930,748 | 17,042,123 | - | - | 118,972,871 |
| 14 | | | | | | | | |
| 15 | LPS - Sch 48 | (sec) | - | 29,145,254 | 22,814,294 | - | - | 51,959,548 |
| 16 | LPS - Sch 48 | (pri) | - | 95,734,013 | 73,496,480 | - | - | 169,230,493 |
| 17 | LPS - Sch 48 | (trn) | - | 134,474,636 | 1,891,067 | - | - | 136,365,703 |
| 18 | LPS - Sch 48 | Total | - | 259,353,903 | 98,201,841 | - | - | 357,555,744 |
| 19 | | | | | | | | |
| 20 | Irg - Sch 41 | (sec) | - | - | - | 32,686,893 | - | 32,686,893 |
| 21 | | | | | | | | |
| 22 | Lgt - Sch 15 | (sec) | - | - | - | - | 839,381 | 839,381 |
| 23 | Lgt - Sch 51 | (sec) | - | - | - | - | 2,902,697 | 2,902,697 |
| 24 | Lgt - Sch 53 | (sec) | - | - | - | - | 486,692 | 486,692 |
| 25 | Lgt - Sch 54 | (sec) | - | - | - | - | 90,540 | 90,540 |
| 26 | Lgt - Total | (sec) | - | - | - | - | 4,319,310 | 4,319,310 |
| 27 | | | | | | | | |
| 28 | Total | | 786,075,316 | 722,358,057 | 125,391,679 | 32,686,893 | 4,319,310 | 1,670,831,255 |

Docket No. UE 433
Exhibit PAC/3506
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Robert M. Meredith**

**Updated Target Functionalized Revenues and Billing Determinants**

**July 2024**

**PACIFIC POWER**
**STATE OF OREGON**
**Functionalized Revenue Targets and Summary of Proposed Functionalized Revenues**
**Forecast 12 Months Ended December 31, 2025**

| Rate Schedule | | Present Revenues ($000) | Cost of Service Revenues ($000) | Target with Unadjusted NPC Revenues ($000) | Summary of Proposed Functionalized Revenues ($000) |
|---|---|---|---|---|---|
| (1) | (2) | (3) | (4) | (5) | (6) |
| **Schedule 4, Residential** | | | | | |
| | Transmission & Ancillary Services[1] | $53,188 | $48,893 | $48,893 | $48,905 |
| | System Usage- Schedule 200 Related | $4,456 | $3,856 | $3,856 | $3,878 |
| | System Usage- T&A and Schedule 201 Related | $6,656 | $7,624 | $7,624 | $7,640 |
| | Distribution | $313,400 | $400,440 | $400,440 | $400,381 |
| | Other Adjustments | $1,100 | $0 | $0 | $0 |
| | Generation Energy - Other (non-NPC) (Sch 200) | $162,632 | $144,623 | $144,623 | $144,633 |
| | Generation Energy - Net Power Costs (Sch 201) | $244,643 | $237,041 | $244,643 | $244,643 |
| | Total | $786,075 | $842,477 | $850,079 | $850,079 |
| **Schedule 23, Small General Service** | | | | | |
| | Transmission & Ancillary Services[1] | $9,064 | $12,109 | $12,109 | $12,109 |
| | System Usage- Schedule 200 Related | $848 | $711 | $711 | $709 |
| | System Usage- T&A and Schedule 201 Related | $1,232 | $1,482 | $1,482 | $1,487 |
| | Distribution | $71,495 | $88,708 | $88,708 | $88,708 |
| | Other Adjustments | $209 | $0 | $0 | $0 |
| | Generation Energy - Other (non-NPC) (Sch 200) | $30,768 | $27,222 | $27,222 | $27,223 |
| | Generation Energy - Net Power Costs (Sch 201) | $46,270 | $44,617 | $46,270 | $46,270 |
| | Total | $159,887 | $174,849 | $176,502 | $176,506 |
| **Schedule 28, General Service 31-200kW** | | | | | |
| Secondary Voltage | | | | | |
| | Transmission & Ancillary Services[1] | $18,256 | $14,872 | $14,872 | $14,913 |
| | System Usage- Schedule 200 Related | $1,471 | $1,317 | $1,317 | $1,308 |
| | System Usage- T&A and Schedule 201 Related | $2,125 | $2,571 | $2,571 | $2,575 |
| | Distribution | $53,469 | $71,698 | $71,698 | $71,651 |
| | Other Adjustments | $368 | $0 | $0 | $0 |
| | Generation Energy - Other (non-NPC) (Sch 200) | $53,431 | $47,442 | $47,442 | $47,445 |
| | Generation Energy - Net Power Costs (Sch 201) | $80,341 | $77,758 | $80,341 | $80,341 |
| | Total | $209,460 | $215,658 | $218,241 | $218,232 |
| Primary Voltage | | | | | |
| | Transmission & Ancillary Services[1] | $116 | $148 | $148 | $148 |
| | System Usage- Schedule 200 Related | $15 | $12 | $12 | $12 |
| | System Usage- T&A and Schedule 201 Related | $22 | $24 | $24 | $24 |
| | Distribution | $345 | $656 | $656 | $656 |
| | Other Adjustments | $4 | $0 | $0 | $0 |
| | Generation Energy - Other (non-NPC) (Sch 200) | $548 | $482 | $482 | $482 |
| | Generation Energy - Net Power Costs (Sch 201) | $824 | $790 | $824 | $824 |
| | Total | $1,874 | $2,113 | $2,146 | $2,147 |
| **Schedule 30, General Service 201-999kW** | | | | | |
| Secondary Voltage | | | | | |
| | Transmission & Ancillary Services[1] | $9,028 | $8,768 | $8,768 | $8,778 |
| | System Usage- Schedule 200 Related | $877 | $775 | $775 | $777 |
| | System Usage- T&A and Schedule 201 Related | $1,265 | $1,508 | $1,508 | $1,503 |
| | Distribution | $19,935 | $31,585 | $31,585 | $31,400 |
| | Other Adjustments | $225 | $0 | $0 | $0 |
| | Generation Energy - Other (non-NPC) (Sch 200) | $32,428 | $28,554 | $28,554 | $28,728 |
| | Generation Energy - Net Power Costs (Sch 201) | $48,295 | $46,801 | $48,295 | $48,295 |
| | Total | $112,053 | $117,991 | $119,485 | $119,481 |
| Primary Voltage | | | | | |
| | Transmission & Ancillary Services[1] | $579 | $521 | $521 | $520 |
| | System Usage- Schedule 200 Related | $54 | $48 | $48 | $48 |
| | System Usage- T&A and Schedule 201 Related | $79 | $94 | $94 | $94 |
| | Distribution | $1,187 | $1,817 | $1,817 | $1,801 |
| | Other Adjustments | $14 | $0 | $0 | $0 |
| | Generation Energy - Other (non-NPC) (Sch 200) | $2,016 | $1,723 | $1,723 | $1,740 |
| | Generation Energy - Net Power Costs (Sch 201) | $2,990 | $2,824 | $2,990 | $2,990 |
| | Total | $6,920 | $7,027 | $7,193 | $7,194 |
| **Schedule 41, Agricultural Pumping Service** | | | | | |
| | Transmission & Ancillary Services[1] | $1,590 | $1,548 | $1,548 | $1,548 |
| | System Usage- Schedule 200 Related | $162 | $129 | $129 | $129 |
| | System Usage- T&A and Schedule 201 Related | $233 | $251 | $251 | $251 |
| | Distribution | $15,804 | $21,908 | $21,908 | $21,908 |
| | Other Adjustments | $40 | $0 | $0 | $0 |
| | Generation Energy - Other (non-NPC) (Sch 200) | $5,934 | $5,210 | $5,210 | $5,210 |
| | Generation Energy - Net Power Costs (Sch 201) | $8,924 | $8,539 | $8,924 | $8,924 |
| | Total | $32,687 | $37,585 | $37,970 | $37,971 |

**PACIFIC POWER**
**STATE OF OREGON**
**Functionalized Revenue Targets and Summary of Proposed Functionalized Revenues**
**Forecast 12 Months Ended December 31, 2025**

| Rate Schedule | | Present Revenues ($000) | Cost of Service Revenues ($000) | Target with Unadjusted NPC Revenues ($000) | Summary of Proposed Functionalized Revenues ($000) |
|---|---|---|---|---|---|
| (1) | (2) | (3) | (4) | (5) | (6) |
| **Schedule 48, Large General Service, 1,000kW and over** | | | | | |
| Secondary Voltage | | | | | |
| | Transmission & Ancillary Services[1] | $4,048 | $3,801 | $3,801 | $3,800 |
| | System Usage- Schedule 200 Related | $400 | $357 | $357 | $354 |
| | System Usage- T&A and Schedule 201 Related | $571 | $691 | $691 | $691 |
| | Distribution | $10,414 | $14,505 | $14,505 | $14,528 |
| | Other Adjustments | $97 | $0 | $0 | $0 |
| | Generation Energy - Other (non-NPC) (Sch 200) | $14,583 | $12,698 | $12,698 | $12,677 |
| | Generation Energy - Net Power Costs (Sch 201) | $21,846 | $20,812 | $21,846 | $21,846 |
| | Total | $51,960 | $52,865 | $53,898 | $53,896 |
| Primary Voltage | | | | | |
| | Transmission & Ancillary Services[1] | $12,390 | $13,534 | $13,534 | $13,550 |
| | System Usage- Schedule 200 Related | $1,455 | $1,264 | $1,264 | $1,259 |
| | System Usage- T&A and Schedule 201 Related | $2,084 | $2,438 | $2,438 | $2,432 |
| | Distribution | $19,170 | $38,226 | $38,226 | $38,224 |
| | Other Adjustments | $369 | $0 | $0 | $0 |
| | Generation Energy - Other (non-NPC) (Sch 200) | $53,651 | $46,725 | $46,725 | $46,723 |
| | Generation Energy - Net Power Costs (Sch 201) | $80,111 | $76,583 | $80,111 | $80,111 |
| | Total | $169,230 | $178,770 | $182,298 | $182,299 |
| Transmission Voltage | | | | | |
| | Transmission & Ancillary Services[1] | $10,739 | $10,780 | $10,780 | $10,768 |
| | System Usage- Schedule 200 Related | $1,258 | $1,096 | $1,096 | $1,103 |
| | System Usage- T&A and Schedule 201 Related | $1,761 | $2,099 | $2,099 | $2,090 |
| | Distribution | $8,883 | $21,751 | $21,751 | $21,764 |
| | Other Adjustments | $329 | $0 | $0 | $0 |
| | Generation Energy - Other (non-NPC) (Sch 200) | $45,130 | $38,950 | $38,950 | $38,958 |
| | Generation Energy - Net Power Costs (Sch 201) | $68,267 | $63,840 | $68,267 | $68,267 |
| | Total | $136,366 | $138,515 | $142,943 | $142,950 |
| **Schedules 15, 51, 53, 54 Lighting** | | | | | |
| Secondary Voltage | | | | | |
| | Transmission & Ancillary Services[1] | $26 | $19 | $19 | $17 |
| | System Usage- Schedule 200 Related | $10 | $8 | $8 | $8 |
| | System Usage- T&A and Schedule 201 Related | $14 | $13 | $13 | $14 |
| | Distribution | $3,256 | $3,628 | $3,628 | $3,629 |
| | Other Adjustments | $5 | $0 | $0 | $0 |
| | Generation Energy - Other (non-NPC) (Sch 200) | $408 | $275 | $275 | $275 |
| | Generation Energy - Net Power Costs (Sch 201) | $600 | $451 | $600 | $600 |
| | Total | $4,319 | $4,394 | $4,543 | $4,543 |
| **TOTAL** | | **$1,670,831** | **$1,772,243** | **$1,795,299** | **$1,795,298** |
| | Employee Discount | -$445 | | -$480 | -$480 |
| Additional Rate Schedules | | | | | |
| | Schedule 47 | $5,048 | | $6,017 | $6,017 |
| | Schedule 848 | $1,517 | | $3,752 | $3,752 |
| **Total Oregon** | | **$1,676,952** | | **$1,804,588** | **$1,804,587** |
| | **Base Revenue Increase (excluding base Insurance Cost Adjustment)** | | | **$127,636** | **$127,635** |

[1]Includes only FERC transmission plus ancillary services revenues. Non-FERC transmission revenues are recovered through distribution charges.

**PACIFIC POWER**
**State of Oregon**
**Billing Determinants**
**Actual 12 Months Ended June 30, 2023**
**Forecast 12 Months Ended December 31, 2025**

| Schedule | Actual 7/22-6/23 Units | Normalized 7/22-6/23 Units | Forecast 1/25 - 12/25 Units | | Present Price | Present Dollars | Proposed Price | Proposed Dollars |
|---|---|---|---|---|---|---|---|---|
| **Schedule No. 4** | | | | | | | | |
| **Residential Service** | | | | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kWh | 6,110,468,412 | 5,814,272,066 | 5,787,620,059 | kWh | 0.919 ¢ | $53,188,228 | 0.845 ¢ | $48,905,389 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 6,110,468,412 | 5,814,272,066 | 5,787,620,059 | kWh | 0.077 ¢ | $4,456,467 | 0.067 ¢ | $3,877,705 |
| T&A and Sch 201 related, per kWh | 6,110,468,412 | 5,814,272,066 | 5,787,620,059 | kWh | 0.115 ¢ | $6,655,763 | 0.132 ¢ | $7,639,658 |
| **Distribution Charge** | | | | | | | | |
| Basic Charge Single Family, per month | 5,114,835 | 5,114,835 | 4,928,360 | bill | $11.00 | $54,211,960 | $16.00 | $78,853,760 |
| Basic Charge Multi Family, per month | 1,281,323 | 1,281,323 | 1,234,609 | bill | $8.00 | $9,876,872 | $9.00 | $11,111,481 |
| Total Bills | 6,396,158 | 6,396,158 | 6,162,969 | bill | | | | |
| Add'l Basic Charge 3 phase, per month | 2,881 | 2,881 | 2,881 | bill | $0.00 | $0 | $9.00 | $25,929 |
| Three Phase Demand Charge, per kW demand | 15,207 | 15,207 | 15,137 | kW | $2.20 | $33,301 | $0.00 | $0 |
| Three Phase Minimum Demand Charge, per month | 1,490 | 1,490 | 1,436 | bill | $3.80 | $5,457 | $0.00 | $0 |
| Distribution Energy Charge, per kWh | 6,110,468,412 | 5,814,272,066 | 5,787,620,059 | kWh | 4.307 ¢ | $249,272,796 | 5.363 ¢ | $310,390,064 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| per kWh | 6,110,468,412 | 5,814,272,066 | 5,787,620,059 | kWh | 2.810 ¢ | $162,632,124 | 2.499 ¢ | $144,632,625 |
| **Subtotal** | 6,110,468,412 | 5,814,272,066 | 5,787,620,059 | kWh | | $540,332,968 | | $605,436,611 |
| Renewable Adjustment Clause (202), per kWh | 6,110,468,412 | 5,814,272,066 | 5,787,620,059 | kWh | 0.019 ¢ | $1,099,648 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 6,110,468,412 | 5,814,272,066 | 5,787,620,059 | kWh | 0.000 ¢ | $0 | 0.406 ¢ | $23,497,737 |
| **Subtotal** | | | | | | $541,432,616 | | $628,934,348 |
| Schedule 201 | | | | | | | | |
| per kWh | 6,110,468,412 | 5,814,272,066 | 5,787,620,059 | kWh | 4.227 ¢ | $244,642,700 | 4.227 ¢ | $244,642,700 |
| **Total** | 6,110,468,412 | 5,814,272,066 | 5,787,620,059 | kWh | | $786,075,316 | | $873,577,048 |
| | | | | | | | Change | $87,501,732 |
| **Schedule No. 4 (Employee Discount)** | | | | | | | | |
| **Residential Service** | | | | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kWh | 13,425,928 | 13,425,928 | 13,364,385 | kWh | 0.919 ¢ | $122,819 | 0.845 ¢ | $112,929 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 13,425,928 | 13,425,928 | 13,364,385 | kWh | 0.077 ¢ | $10,291 | 0.067 ¢ | $8,954 |
| T&A and Sch 201 related, per kWh | 13,425,928 | 13,425,928 | 13,364,385 | kWh | 0.115 ¢ | $15,369 | 0.132 ¢ | $17,641 |
| **Distribution Charge** | | | | | | | | |
| Basic Charge Single Family, per month | 10,403 | 10,403 | 10,024 | bill | $11.00 | $110,264 | $16.00 | $160,384 |
| Basic Charge Multi Family, per month | 388 | 388 | 374 | bill | $8.00 | $2,992 | $9.00 | $3,366 |
| Total Bills | 10,791 | 10,791 | 10,398 | bill | | | | |
| Three Phase Demand Charge, per kW demand | 0 | 0 | 0 | kW | $2.20 | $0 | $0.00 | $0 |
| Three Phase Minimum Demand Charge, per month | 0 | 0 | 0 | bill | $3.80 | $0 | $0.00 | $0 |
| Distribution Energy Charge, per kWh | 13,425,928 | 13,425,928 | 13,364,385 | kWh | 4.307 ¢ | $575,604 | 5.363 ¢ | $716,732 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| per kWh | 13,425,928 | 13,425,928 | 13,364,385 | kWh | 2.810 ¢ | $375,539 | 2.499 ¢ | $333,976 |
| **Subtotal** | 13,425,928 | 13,425,928 | 13,364,385 | kWh | | $1,212,878 | | $1,353,982 |
| Renewable Adjustment Clause (202), per kWh | 13,425,928 | 13,425,928 | 13,364,385 | kWh | 0.019 ¢ | $2,539 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 13,425,928 | 13,425,928 | 13,364,385 | kWh | 0.000 ¢ | $0 | 0.406 ¢ | $54,259 |
| **Subtotal** | | | | | | $1,215,417 | | $1,408,241 |
| Schedule 201 | | | | | | | | |
| per kWh | 13,425,928 | 13,425,928 | 13,364,385 | kWh | 4.227 ¢ | $564,913 | 4.227 ¢ | $564,913 |
| **Total** | 13,425,928 | 13,425,928 | 13,364,385 | kWh | | $1,780,330 | | $1,973,154 |
| Schedule 80 Employee Discount | | | | | | $0 | | ($13,565) |
| Schedule 201 Employee Discount | | | | | | ($141,228) | | ($141,228) |
| **Total Employee Discount** | | | | | | ($445,083) | | ($493,289) |
| | | | | | | | Change | ($48,206) |

**PACIFIC POWER**
**State of Oregon**
**Billing Determinants**
**Actual 12 Months Ended June 30, 2023**
**Forecast 12 Months Ended December 31, 2025**

| Schedule | Actual 7/22-6/23 Units | Normalized 7/22-6/23 Units | Forecast 1/25 - 12/25 Units | | Present Price | Present Dollars | Proposed Price | Proposed Dollars |
|---|---|---|---|---|---|---|---|---|
| **Schedule No. 23/723 - Composite** | | | | | | | | |
| **General Service (Secondary)** | | | | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kWh | 1,226,088,608 | 1,198,399,389 | 1,160,255,186 | kWh | 0.780 ¢ | $9,049,990 | 1.042 ¢ | $12,089,859 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 1,226,088,608 | 1,198,399,389 | 1,160,255,186 | kWh | 0.073 ¢ | $846,986 | 0.061 ¢ | $707,756 |
| T&A and Sch 201 related, per kWh | 1,226,088,608 | 1,198,399,389 | 1,160,255,186 | kWh | 0.106 ¢ | $1,229,870 | 0.128 ¢ | $1,485,127 |
| **Distribution Charge** | | | | | | | | |
| Basic Charge | | | | | | | | |
| Single Phase, per month | 787,771 | 787,771 | 789,568 | bill | $17.35 | $13,699,005 | $21.55 | $17,015,190 |
| Three Phase, per month | 247,366 | 247,366 | 247,001 | bill | $25.90 | $6,397,326 | $32.15 | $7,941,082 |
| Load Size Charge | | | | | | | | |
| ≤ 15 kW | | | | | No Charge | | No Charge | |
| per kW for all kW in excess of 15 kW | 1,174,160 | 1,174,160 | 1,136,126 | kW | $1.65 | $1,874,608 | $2.05 | $2,329,058 |
| Demand Charge, the first 15 kW of demand | | | | | No Charge | | No Charge | |
| Demand Charge, per kW for all kW in excess of 15 kW | 575,803 | 575,803 | 557,113 | kW | $5.40 | $3,008,410 | $6.70 | $3,732,657 |
| Reactive Power Charge, per kvar | 214,425 | 214,425 | 206,864 | kvar | 65.00 ¢ | $134,462 | 65.00 ¢ | $134,462 |
| Distribution Energy Charge, per kWh | 1,226,088,608 | 1,198,399,389 | 1,160,255,186 | kWh | 3.989 ¢ | $46,282,579 | 4.950 ¢ | $57,432,632 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| 1st 3,000 kWh, per kWh | 960,906,746 | 938,853,746 | 909,353,739 | kWh | 2.804 ¢ | $25,498,279 | 2.481 ¢ | $22,561,066 |
| All additional kWh, per kWh | 265,181,862 | 259,545,643 | 250,901,447 | kWh | 2.082 ¢ | $5,223,768 | 1.842 ¢ | $4,621,605 |
| **Subtotal** | 1,226,088,608 | 1,198,399,389 | 1,160,255,186 | kWh | | $113,245,283 | | $130,050,494 |
| Renewable Adjustment Clause (202), per kWh | 1,226,088,608 | 1,198,399,389 | 1,160,255,186 | kWh | 0.018 ¢ | $208,846 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 1,226,088,608 | 1,198,399,389 | 1,160,255,186 | kWh | 0.000 ¢ | $0 | 0.420 ¢ | $4,873,072 |
| **Subtotal** | | | | | | $113,454,129 | | $134,923,566 |
| Schedule 201 | | | | | | | | |
| 1st 3,000 kWh, per kWh | 960,906,746 | 938,853,746 | 909,353,739 | kWh | 4.218 ¢ | $38,356,541 | 4.218 ¢ | $38,356,541 |
| All additional kWh, per kWh | 265,181,862 | 259,545,643 | 250,901,447 | kWh | 3.127 ¢ | $7,845,688 | 3.127 ¢ | $7,845,688 |
| **Total** | 1,226,088,608 | 1,198,399,389 | 1,160,255,186 | kWh | | $159,656,358 | | $181,125,795 |
| | | | | | | | Change | $21,469,437 |
| **Schedule No. 23/723 - Composite** | | | | | | | | |
| **General Service (Primary)** | | | | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kWh | 1,955,057 | 1,955,057 | 1,877,049 | kWh | 0.768 ¢ | $14,416 | 1.026 ¢ | $19,259 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 1,955,057 | 1,955,057 | 1,877,049 | kWh | 0.072 ¢ | $1,351 | 0.060 ¢ | $1,126 |
| T&A and Sch 201 related, per kWh | 1,955,057 | 1,955,057 | 1,877,049 | kWh | 0.104 ¢ | $1,952 | 0.126 ¢ | $2,365 |
| **Distribution Charge** | | | | | | | | |
| Basic Charge | | | | | | | | |
| Single Phase, per month | 211 | 211 | 211 | bill | $17.35 | $3,661 | $21.55 | $4,547 |
| Three Phase, per month | 393 | 393 | 392 | bill | $25.90 | $10,153 | $32.15 | $12,603 |
| Load Size Charge | | | | | | | | |
| ≤ 15 kW | | | | | No Charge | | No Charge | |
| per kW for all kW in excess of 15 kW | 2,381 | 2,381 | 2,278 | kW | $1.65 | $3,759 | $2.05 | $4,670 |
| Demand Charge, the first 15 kW of demand | | | | | No Charge | | No Charge | |
| Demand Charge, per kW for all kW in excess of 15 kW | 1,316 | 1,316 | 1,255 | kW | $5.33 | $6,689 | $6.61 | $8,296 |
| Reactive Power Charge, per kvar | 1,721 | 1,721 | 1,654 | kvar | 60.00 ¢ | $992 | 60.00 ¢ | $992 |
| Distribution Energy Charge, per kWh | 1,955,057 | 1,955,057 | 1,877,049 | kWh | 3.927 ¢ | $73,712 | 4.873 ¢ | $91,469 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| 1st 3,000 kWh, per kWh | 1,057,095 | 1,057,095 | 1,018,579 | kWh | 2.761 ¢ | $28,123 | 2.443 ¢ | $24,884 |
| All additional kWh, per kWh | 897,962 | 897,962 | 858,470 | kWh | 2.050 ¢ | $17,599 | 1.813 ¢ | $15,564 |
| **Subtotal** | 1,955,057 | 1,955,057 | 1,877,049 | kWh | | $162,407 | | $185,775 |
| Renewable Adjustment Clause (202), per kWh | 1,955,057 | 1,955,057 | 1,877,049 | kWh | 0.018 ¢ | $338 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 1,955,057 | 1,955,057 | 1,877,049 | kWh | 0.000 ¢ | $0 | 0.420 ¢ | $7,884 |
| **Subtotal** | | | | | | $162,745 | | $193,659 |
| Schedule 201 | | | | | | | | |
| 1st 3,000 kWh, per kWh | 1,057,095 | 1,057,095 | 1,018,579 | kWh | 4.090 ¢ | $41,660 | 4.090 ¢ | $41,660 |
| All additional kWh, per kWh | 897,962 | 897,962 | 858,470 | kWh | 3.033 ¢ | $26,037 | 3.033 ¢ | $26,037 |
| **Total** | 1,955,057 | 1,955,057 | 1,877,049 | kWh | | $230,442 | | $261,356 |
| | | | | | | | Change | $30,914 |

**PACIFIC POWER**
**State of Oregon**
**Billing Determinants**
**Actual 12 Months Ended June 30, 2023**
**Forecast 12 Months Ended December 31, 2025**

| Schedule | Actual 7/22-6/23 Units | Normalized 7/22-6/23 Units | Forecast 1/25 - 12/25 Units | | Present Price | Present Dollars | Proposed Price | Proposed Dollars |
|---|---|---|---|---|---|---|---|---|
| **Schedule No. 28/728 - Composite** | | | | | | | | |
| **Large General Service - (Secondary)** | | | | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kW | 8,582,972 | 8,582,972 | 8,570,763 | kW | $2.13 | $18,255,725 | $1.74 | $14,913,128 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 2,085,565,751 | 2,044,568,075 | 2,043,261,478 | kWh | 0.072 ¢ | $1,471,148 | 0.064 ¢ | $1,307,687 |
| T&A and Sch 201 related, per kWh | 2,085,565,751 | 2,044,568,075 | 2,043,261,478 | kWh | 0.104 ¢ | $2,124,992 | 0.126 ¢ | $2,574,509 |
| **Distribution Charge** | | | | | | | | |
| Basic Charge | | | | | | | | |
| Load Size ≤ 50 kW, per month | 58,094 | 58,094 | 59,242 | bill | $18.00 | $1,066,356 | $24.00 | $1,421,808 |
| Load Size 51-100 kW, per month | 42,437 | 42,437 | 43,244 | bill | $34.00 | $1,470,296 | $46.00 | $1,989,224 |
| Load Size 101-300 kW, per month | 23,536 | 23,536 | 23,972 | bill | $81.00 | $1,941,732 | $109.00 | $2,612,948 |
| Load Size > 300 kW, per month | 719 | 719 | 733 | bill | $114.00 | $83,562 | $153.00 | $112,149 |
| Load Size Charge | | | | | | | | |
| ≤ 50 kW, per kW | 2,240,586 | 2,240,586 | 2,240,880 | kW | $1.15 | $2,577,012 | $1.55 | $3,473,364 |
| 51-100 kW, per kW | 2,980,722 | 2,980,722 | 2,975,675 | kW | $0.90 | $2,678,108 | $1.20 | $3,570,810 |
| 101-300 kW, per kW | 3,587,692 | 3,587,692 | 3,579,714 | kW | $0.55 | $1,968,843 | $0.75 | $2,684,786 |
| >300 kW, per kW | 314,004 | 314,004 | 313,436 | kW | $0.35 | $109,703 | $0.45 | $141,046 |
| Demand Charge, per kW | 8,582,972 | 8,582,972 | 8,570,763 | kW | $3.87 | $33,168,853 | $5.19 | $44,482,260 |
| Reactive Power Charge, per kvar | 612,785 | 612,785 | 606,848 | kvar | 65.00 ¢ | $394,451 | 65.00 ¢ | $394,451 |
| Distribution Energy Charge, per kWh | 2,085,565,751 | 2,044,568,075 | 2,043,261,478 | kWh | 0.392 ¢ | $8,009,585 | 0.527 ¢ | $10,767,988 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| All kWh, per kWh | 2,085,565,751 | 2,044,568,075 | 2,043,261,478 | kWh | 2.615 ¢ | $53,431,288 | 2.322 ¢ | $47,444,532 |
| **Subtotal** | 2,085,565,751 | 2,044,568,075 | 2,043,261,478 | kWh | | $128,751,654 | | $137,890,690 |
| Renewable Adjustment Clause (202), per kWh | 2,085,565,751 | 2,044,568,075 | 2,043,261,478 | kWh | 0.018 ¢ | $367,787 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 2,085,565,751 | 2,044,568,075 | 2,043,261,478 | kWh | 0.000 ¢ | $0 | 0.295 ¢ | $6,027,621 |
| **Subtotal** | | | | | | $129,119,441 | | $143,918,311 |
| Schedule 201 | | | | | | | | |
| All kWh, per kWh | 2,085,565,751 | 2,044,568,075 | 2,043,261,478 | kWh | 3.932 ¢ | $80,341,041 | 3.932 ¢ | $80,341,041 |
| **Total** | 2,085,565,751 | 2,044,568,075 | 2,043,261,478 | kWh | | $209,460,482 | | $224,259,352 |
| | | | | | | | Change | $14,798,870 |
| **Schedule No. 28/728 - Composite** | | | | | | | | |
| **Large General Service - (Primary)** | | | | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kW | 70,611 | 70,611 | 69,598 | kW | $1.67 | $116,229 | $2.13 | $148,244 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 21,808,533 | 21,808,533 | 21,450,524 | kWh | 0.070 ¢ | $15,015 | 0.057 ¢ | $12,227 |
| T&A and Sch 201 related, per kWh | 21,808,533 | 21,808,533 | 21,450,524 | kWh | 0.102 ¢ | $21,880 | 0.111 ¢ | $23,810 |
| **Distribution Charge** | | | | | | | | |
| Basic Charge | | | | | | | | |
| Load Size ≤ 50 kW, per month | 122 | 122 | 124 | bill | $18.00 | $2,232 | $34.00 | $4,216 |
| Load Size 51-100 kW, per month | 193 | 193 | 194 | bill | $31.00 | $6,014 | $59.00 | $11,446 |
| Load Size 101-300 kW, per month | 339 | 339 | 344 | bill | $71.00 | $24,424 | $135.00 | $46,440 |
| Load Size > 300 kW, per month | 48 | 48 | 48 | bill | $101.00 | $4,848 | $192.00 | $9,216 |
| Load Size Charge | | | | | | | | |
| ≤ 50 kW, per kW | 4,691 | 4,691 | 4,657 | kW | $1.00 | $4,657 | $1.90 | $8,848 |
| 51-100 kW, per kW | 14,503 | 14,503 | 14,170 | kW | $0.80 | $11,336 | $1.50 | $21,255 |
| 101-300 kW, per kW | 63,140 | 63,140 | 62,442 | kW | $0.50 | $31,221 | $0.95 | $59,320 |
| >300 kW, per kW | 21,330 | 21,330 | 20,680 | kW | $0.25 | $5,170 | $0.50 | $10,340 |
| Demand Charge, per kW | 70,611 | 70,611 | 69,598 | kW | $3.48 | $242,201 | $6.62 | $460,739 |
| Reactive Power Charge, per kvar | 7,845 | 7,845 | 7,699 | kvar | 60.00 ¢ | $4,619 | 60.00 ¢ | $4,619 |
| Distribution Energy Charge, per kWh | 21,808,533 | 21,808,533 | 21,450,524 | kWh | 0.038 ¢ | $8,151 | 0.091 ¢ | $19,520 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| All kWh, per kWh | 21,808,533 | 21,808,533 | 21,450,524 | kWh | 2.554 ¢ | $547,846 | 2.248 ¢ | $482,208 |
| **Subtotal** | 21,808,533 | 21,808,533 | 21,450,524 | kWh | | $1,045,843 | | $1,322,448 |
| Renewable Adjustment Clause (202), per kWh | 21,808,533 | 21,808,533 | 21,450,524 | kWh | 0.018 ¢ | $3,861 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 21,808,533 | 21,808,533 | 21,450,524 | kWh | 0.000 ¢ | $0 | 0.295 ¢ | $63,279 |
| **Subtotal** | | | | | | $1,049,704 | | $1,385,727 |
| Schedule 201 | | | | | | | | |
| All kWh, per kWh | 21,808,533 | 21,808,533 | 21,450,524 | kWh | 3.842 ¢ | $824,129 | 3.842 ¢ | $824,129 |
| **Total** | 21,808,533 | 21,808,533 | 21,450,524 | kWh | | $1,873,833 | | $2,209,856 |
| | | | | | | | Change | $336,023 |

**PACIFIC POWER**
**State of Oregon**
**Billing Determinants**
**Actual 12 Months Ended June 30, 2023**
**Forecast 12 Months Ended December 31, 2025**

| Schedule | Actual 7/22-6/23 Units | Normalized 7/22-6/23 Units | Forecast 1/25 - 12/25 Units | | Present Price | Present Dollars | Proposed Price | Proposed Dollars |
|---|---|---|---|---|---|---|---|---|
| **Schedule No. 30/730 - Composite** | | | | | | | | |
| **Large General Service - (Secondary)** | | | | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kW | 3,518,544 | 3,518,544 | 3,582,710 | kW | $2.52 | $9,028,429 | $2.45 | $8,777,640 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 1,249,187,259 | 1,226,112,463 | 1,252,474,015 | kWh | 0.070 ¢ | $876,732 | 0.062 ¢ | $776,534 |
| T&A and Sch 201 related, per kWh | 1,249,187,259 | 1,226,112,463 | 1,252,474,015 | kWh | 0.101 ¢ | $1,264,999 | 0.120 ¢ | $1,502,969 |
| **Distribution Charge** | | | | | | | | |
| Basic Charge | | | | | | | | |
| Load Size ≤ 200 kW, per month | 158 | 158 | 159 | bill | $436.00 | $69,324 | $690.00 | $109,710 |
| Load Size 201-300 kW, per month | 2,505 | 2,505 | 2,529 | bill | $126.00 | $318,654 | $200.00 | $505,800 |
| Load Size > 300 kW, per month | 6,922 | 6,922 | 6,990 | bill | $334.00 | $2,334,660 | $529.00 | $3,697,710 |
| Load Size Charge | | | | | | | | |
| ≤ 200 Kw, per kW | | | | | No Charge | $0 | No Charge | $0 |
| 201-300 kW, per kW | 651,402 | 651,402 | 665,587 | kW | $1.55 | $1,031,660 | $2.45 | $1,630,688 |
| >300 kW, per kW | 3,510,622 | 3,510,622 | 3,575,964 | kW | $0.75 | $2,681,973 | $1.20 | $4,291,157 |
| Demand Charge, per kW | 3,518,544 | 3,518,544 | 3,582,710 | kW | $3.66 | $13,112,719 | $5.80 | $20,779,718 |
| Reactive Power Charge, per kvar | 593,103 | 593,103 | 593,199 | kvar | 65.00 ¢ | $385,579 | 65.00 ¢ | $385,579 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| Demand Charge, per kW | 3,518,544 | 3,518,544 | 3,582,710 | kW | $5.80 | $20,779,718 | $5.11 | $18,307,648 |
| All kWh, per kWh | 1,249,187,259 | 1,226,112,463 | 1,252,474,015 | kWh | 0.930 ¢ | $11,648,008 | 0.832 ¢ | $10,420,584 |
| **Subtotal** | 1,249,187,259 | 1,226,112,463 | 1,252,474,015 | kWh | | $63,532,455 | | $71,185,737 |
| Renewable Adjustment Clause (202), per kWh | 1,249,187,259 | 1,226,112,463 | 1,252,474,015 | kWh | 0.018 ¢ | $225,445 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 1,249,187,259 | 1,226,112,463 | 1,252,474,015 | kWh | 0.000 ¢ | $0 | 0.263 ¢ | $3,294,007 |
| **Subtotal** | | | | | | $63,757,900 | | $74,479,744 |
| Schedule 201 | | | | | | | | |
| All kWh, per kWh | 1,249,187,259 | 1,226,112,463 | 1,252,474,015 | kWh | 3.856 ¢ | $48,295,398 | 3.856 ¢ | $48,295,398 |
| **Total** | 1,249,187,259 | 1,226,112,463 | 1,252,474,015 | kWh | | $112,053,298 | | $122,775,142 |
| | | | | | | | Change | $10,721,844 |
| **Schedule No. 30/730 - Composite** | | | | | | | | |
| **Large General Service - (Primary)** | | | | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kW | 224,316 | 224,316 | 227,103 | kW | $2.55 | $579,113 | $2.29 | $520,066 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 76,532,211 | 76,532,211 | 77,804,770 | kWh | 0.070 ¢ | $54,463 | 0.062 ¢ | $48,239 |
| T&A and Sch 201 related, per kWh | 76,532,211 | 76,532,211 | 77,804,770 | kWh | 0.102 ¢ | $79,361 | 0.121 ¢ | $94,144 |
| **Distribution Charge** | | | | | | | | |
| Basic Charge | | | | | | | | |
| Load Size ≤ 200 kW, per month | 0 | 0 | 0 | bill | $409.00 | $0 | $628.00 | $0.00 |
| Load Size 201-300 kW, per month | 48 | 48 | 48 | bill | $129.00 | $6,192 | $198.00 | $9,504.00 |
| Load Size > 300 kW, per month | 438 | 438 | 443 | bill | $337.00 | $149,291 | $516.00 | $228,588.00 |
| Load Size Charge | | | | | | | | |
| ≤ 200 Kw, per kW | | | | | No Charge | | No Charge | |
| 201-300 kW, per kW | 12,560 | 12,560 | 12,952 | kW | $1.40 | $18,133 | $2.15 | $27,847 |
| >300 kW, per kW | 254,858 | 254,858 | 258,240 | kW | $0.70 | $180,768 | $1.05 | $271,152 |
| Demand Charge, per kW | 224,316 | 224,316 | 227,103 | kW | $3.57 | $810,758 | $5.47 | $1,242,253 |
| Reactive Power Charge, per kvar | 36,888 | 36,888 | 35,946 | kvar | 60.00 ¢ | $21,568 | 60.00 ¢ | $21,568 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| Demand Charge, per kW | 224,316 | 224,316 | 227,103 | kW | $5.80 | $1,317,197 | $4.96 | $1,126,431 |
| All kWh, per kWh | 76,532,211 | 76,532,211 | 77,804,770 | kWh | 0.898 ¢ | $698,687 | 0.789 ¢ | $613,880 |
| **Subtotal** | 76,532,211 | 76,532,211 | 77,804,770 | kWh | | $3,915,531 | | $4,203,672 |
| Renewable Adjustment Clause (202), per kWh | 76,532,211 | 76,532,211 | 77,804,770 | kWh | 0.018 ¢ | $14,005 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 76,532,211 | 76,532,211 | 77,804,770 | kWh | 0.000 ¢ | $0 | 0.263 ¢ | $204,627 |
| **Subtotal** | | | | | | $3,929,536 | | $4,408,299 |
| Schedule 201 | | | | | | | | |
| All kWh, per kWh | 76,532,211 | 76,532,211 | 77,804,770 | kWh | 3.843 ¢ | $2,990,037 | 3.843 ¢ | $2,990,037 |
| **Total** | 76,532,211 | 76,532,211 | 77,804,770 | kWh | | $6,919,573 | | $7,398,336 |
| | | | | | | | Change | $478,763 |

**PACIFIC POWER**
**State of Oregon**
**Billing Determinants**
**Actual 12 Months Ended June 30, 2023**
**Forecast 12 Months Ended December 31, 2025**

| Schedule | Actual 7/22-6/23 Units | Normalized 7/22-6/23 Units | Forecast 1/25 - 12/25 Units | | Present Price | Present Dollars | Proposed Price | Proposed Dollars |
|---|---|---|---|---|---|---|---|---|
| **Schedule No. 41/741 - Irrigation** | | | | | | | | |
| **Agricultural Pumping Service (Secondary)** | | | | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kWh | 196,326,232 | 171,439,514 | 234,909,530 | kWh | 0.677 ¢ | $1,590,338 | 0.659 ¢ | $1,548,054 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 196,326,232 | 171,439,514 | 234,909,530 | kWh | 0.069 ¢ | $162,088 | 0.055 ¢ | $129,200 |
| T&A and Sch 201 related, per kWh | 196,326,232 | 171,439,514 | 234,909,530 | kWh | 0.099 ¢ | $232,560 | 0.107 ¢ | $251,353 |
| **Distribution Charge** | | | | | | | | |
| Basic Charge (billed in November) | | | | | | | | |
| Load Size ≤ 50 kW, or Single Phase Any Size | 5,221 | 5,221 | 5,155 | bill | No Charge | $0 | No Charge | $0 |
| Three Phase Load Size 51 - 300 kW, per customer | 910 | 910 | 899 | bill | $410.00 | $368,590 | $570.00 | $512,430 |
| Three Phase Load Size > 300 kW, per customer | 19 | 19 | 19 | bill | $1,620.00 | $30,780 | $2,250.00 | $42,750 |
| Total Annual Bills | 6,150 | 6,150 | 6,073 | | | | | |
| Average Customers | 7,984 | 7,984 | 7,884 | | | | | |
| Monthly Bills | 40,234 | 40,234 | 39,729 | | | | | |
| Load Size Charge (billed in November) | | | | | | | | |
| Single Phase Any Size, Three Phase ≤ 50 kW | 85,192 | 85,192 | 116,732 | kW | $17.10 | $1,996,117 | $23.70 | $2,766,548 |
| Three Phase Load Size 51-300 kW, per kW | 81,745 | 81,745 | 112,008 | kW | $11.70 | $1,310,494 | $16.20 | $1,814,530 |
| Three Phase Load Size > 300 kW, per kW | 8,090 | 8,090 | 11,085 | kW | $7.20 | $79,812 | $10.00 | $110,850 |
| Single Phase, Minimum Charge | 408 | 408 | 403 | bill | $75.00 | $30,225 | $105.00 | $42,315 |
| Three Phase, Minimum Charge | 1,756 | 1,756 | 1,734 | bill | $120.00 | $208,080 | $165.00 | $286,110 |
| Distribution Energy Charge, per kWh | 196,326,232 | 171,439,514 | 234,909,530 | kWh | 4.950 ¢ | $11,628,022 | 6.888 ¢ | $16,180,568 |
| Reactive Power Charge, per kvar | 170,466 | 170,466 | 233,576 | kvar | 65.00 ¢ | $151,824 | 65.00 ¢ | $151,824 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| All kWh, per kWh | 196,326,232 | 171,439,514 | 234,909,530 | kWh | 2.526 ¢ | $5,933,815 | 2.218 ¢ | $5,210,293 |
| **Subtotal** | 196,326,232 | 171,439,514 | 234,909,530 | kWh | | $23,722,745 | | $29,046,825 |
| Renewable Adjustment Clause (202), per kWh | 196,326,232 | 171,439,514 | 234,909,530 | kWh | 0.017 ¢ | $39,935 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 196,326,232 | 171,439,514 | 234,909,530 | kWh | 0.000 ¢ | $0 | 0.446 ¢ | $1,047,697 |
| **Subtotal** | | | | | | $23,762,680 | | $30,094,522 |
| Schedule 201 | | | | | | | | |
| All kWh, per kWh | 196,326,232 | 171,439,514 | 234,909,530 | kWh | 3.799 ¢ | $8,924,213 | 3.799 ¢ | $8,924,213 |
| Option A Summer On Peak Adder, per On-peak kWh | 0 | 0 | 11,109,862 | kWh | 4.989 ¢ | $0 | 12.030 ¢ | $1,336,516 |
| Option B Summer On Peak Adder, per On-peak kWh | 0 | 0 | 11,082,022 | kWh | 4.989 ¢ | $0 | 12.030 ¢ | $1,333,167 |
| Summer Off Peak Adder, per Off-peak kWh | 0 | 0 | 99,032,240 | kWh | -0.992 ¢ | $0 | -2.696 ¢ | ($2,669,909) |
| **Total** | 196,326,232 | 171,439,514 | 234,909,530 | kWh | | $32,686,893 | | $39,018,509 |
| | | | | | | | Change | $6,331,616 |
| **Schedule No. 41/741 - Irrigation** | | | | | | | | |
| **Agricultural Pumping Service (Primary)** | | | | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kWh | 0 | 0 | 0 | kWh | 0.667 ¢ | $0 | 0.649 ¢ | $0 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 0 | 0 | 0 | kWh | 0.068 ¢ | $0 | 0.054 ¢ | $0 |
| T&A and Sch 201 related, per kWh | 0 | 0 | 0 | kWh | 0.097 ¢ | $0 | 0.105 ¢ | $0 |
| **Distribution Charge** | | | | | | | | |
| Basic Charge (billed in November) | | | | | | | | |
| Load Size ≤ 50 kW, or Single Phase Any Size | 0 | 0 | 0 | bill | No Charge | $0 | No Charge | $0 |
| Three Phase Load Size 51 - 300 kW, per customer | 0 | 0 | 0 | bill | $400.00 | $0 | $560.00 | $0 |
| Three Phase Load Size > 300 kW, per customer | 0 | 0 | 0 | bill | $1,600.00 | $0 | $2,220.00 | $0 |
| Total Annual Bills | 0 | 0 | 0 | | | | | |
| Average Customers | 0 | 0 | 0 | | | | | |
| Monthly Bills | 0 | 0 | 0 | | | | | |
| Load Size Charge (billed in November) | | | | | | | | |
| Single Phase Any Size, Three Phase ≤ 50 kW | 0 | 0 | 0 | kW | $16.90 | $0 | $23.40 | $0 |
| Three Phase Load Size 51-300 kW, per kW | 0 | 0 | 0 | kW | $11.50 | $0 | $16.00 | $0 |
| Three Phase Load Size > 300 kW, per kW | 0 | 0 | 0 | kW | $7.10 | $0 | $9.90 | $0 |
| Single Phase, Minimum Charge | 0 | 0 | 0 | bill | $75.00 | $0 | $105.00 | $0 |
| Three Phase, Minimum Charge | 0 | 0 | 0 | bill | $120.00 | $0 | $165.00 | $0 |
| Distribution Energy Charge, per kWh | 0 | 0 | 0 | kWh | 4.873 ¢ | $0 | 6.781 ¢ | $0 |
| Reactive Power Charge, per kvar | 0 | 0 | 0 | kvar | 60.00 ¢ | $0 | 60.00 ¢ | $0 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| All kWh, per kWh | 0 | 0 | 0 | kWh | 2.487 ¢ | $0 | 2.184 ¢ | $0 |
| **Subtotal** | 0 | 0 | 0 | kWh | | $0 | | $0 |
| Renewable Adjustment Clause (202), per kWh | 0 | 0 | 0 | kWh | 0.017 ¢ | $0 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 0 | 0 | 0 | kWh | 0.000 ¢ | $0 | 0.446 ¢ | $0 |
| **Subtotal** | | | | | | $0 | | $0 |
| Schedule 201 | | | | | | | | |
| All kWh, per kWh | 0 | 0 | 0 | kWh | 3.739 ¢ | $0 | 3.739 ¢ | $0 |
| Option A Summer On Peak Adder, per On-peak kWh | 0 | 0 | 0 | kWh | 4.989 ¢ | $0 | 12.030 ¢ | $0 |
| Option B Summer On Peak Adder, per On-peak kWh | 0 | 0 | 0 | kWh | 4.989 ¢ | $0 | 12.030 ¢ | $0 |
| Summer Off Peak Adder, per Off-peak kWh | 0 | 0 | 0 | kWh | -0.992 ¢ | $0 | -2.696 ¢ | $0 |
| **Total** | 0 | 0 | 0 | kWh | | $0 | | $0 |
| | | | | | | | Change | $0 |

**PACIFIC POWER**
**State of Oregon**
**Billing Determinants**
**Actual 12 Months Ended June 30, 2023**
**Forecast 12 Months Ended December 31, 2025**

| Schedule | Actual 7/22-6/23 Units | Normalized 7/22-6/23 Units | Forecast 1/25 - 12/25 Units | | Present Price | Present Dollars | Proposed Price | Proposed Dollars |
|---|---|---|---|---|---|---|---|---|
| **Schedule No. 47/747 - Composite** | | | | | | | | |
| **Large General Service - Partial Requirement (Primary)** | | | | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kW of on-peak demand | 166,370 | 166,370 | 158,737 | kW | $2.45 | $388,906 | $2.73 | $433,352 |
| credit per kW of on-peak demand (OATT) | 0 | 0 | 0 | kW | ($2.45) | $0 | ($2.73) | $0 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 34,535,247 | 34,535,247 | 32,950,858 | kWh | 0.067 ¢ | $22,077 | 0.058 ¢ | $19,111 |
| T&A and Sch 201 related, per kWh | 34,535,247 | 34,535,247 | 32,950,858 | kWh | 0.096 ¢ | $31,633 | 0.112 ¢ | $36,905 |
| **Distribution Charge** | | | | | | | | |
| Basic Charge | | | | | | | | |
| Facility Capacity ≤ 4,000 kW, per month | 0 | 0 | 0 | bill | $570.00 | $0 | $1,140.00 | $0 |
| Facility Capacity > 4,000 kW, per month | 24 | 24 | 24 | bill | $1,570.00 | $37,680 | $3,130.00 | $75,120 |
| Facilities Charge | | | | | | | | |
| Facility Capacity ≤ 4,000 kW, per kW | 0 | 0 | 0 | kW | $1.25 | $0 | $1.35 | $0 |
| Facility Capacity > 4,000 kW, per kW | 238,892 | 238,892 | 227,932 | kW | $0.50 | $113,966 | $0.55 | $125,363 |
| Demand Charge, per kW of on-peak demand | 166,370 | 166,370 | 158,737 | kW | $3.46 | $549,230 | $7.77 | $1,233,386 |
| Reactive Power Charge, per kvar | 1,829 | 1,829 | 1,745 | kvar | 60.00 ¢ | $1,047 | 60.00 ¢ | $1,047 |
| Reactive Hours, per kvarh | 5,840,000 | 5,840,000 | 5,572,076 | kvarh | 0.080 ¢ | $4,458 | 0.080 ¢ | $4,458 |
| Reserves Charges | | | | | | | | |
| Spinning Reserves, per kW of Facility Cap. | 238,892 | 238,892 | 227,932 | kW | $0.27 | $61,542 | $0.27 | $61,542 |
| Supplemental Reserves, per kW of Facility Cap. | 238,892 | 238,892 | 227,932 | kW | $0.27 | $61,542 | $0.27 | $61,542 |
| Spinning Reserves Credit, per kW of Facility Cap. | 0 | 0 | 0 | kW | ($0.27) | $0 | ($0.27) | $0 |
| Supplemental Reserves Credit, per kW Facil. Cap. | 0 | 0 | 0 | kW | ($0.27) | $0 | ($0.27) | $0 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| Demand Charge, per kW of On-Peak demand | 166,370 | 166,370 | 158,737 | kW | $1.65 | $261,916 | $1.44 | $228,581 |
| On-Peak, per on-peak kWh | 13,996,483 | 13,996,483 | 13,354,360 | kWh | 2.156 ¢ | $287,920 | 1.877 ¢ | $250,661 |
| Off-Peak, per off-peak kWh | 20,538,764 | 20,538,764 | 19,596,498 | kWh | 2.156 ¢ | $422,500 | 1.877 ¢ | $367,826 |
| **Unscheduled Energy, per kWh** | 4,037,353 | 4,037,353 | 3,852,130 | kWh | | $372,143 | | $372,143 |
| **Subtotal** | 38,572,600 | 38,572,600 | 36,802,988 | kWh | | $2,616,560 | | $3,271,037 |
| Renewable Adjustment Clause (202), per kWh | 38,572,600 | 38,572,600 | 36,802,988 | kWh | 0.017 ¢ | $6,257 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 38,572,600 | 38,572,600 | 36,802,988 | kWh | 0.000 ¢ | $0 | 0.224 ¢ | $82,439 |
| **Subtotal** | | | | | | $2,622,817 | | $3,353,476 |
| Schedule 201 | | | | | | | | |
| On-Peak, per on-peak kWh | 13,996,483 | 13,996,483 | 13,354,360 | kWh | 4.500 ¢ | $600,946 | 4.500 ¢ | $600,946 |
| Off-Peak, per off-peak kWh | 20,538,764 | 20,538,764 | 19,596,498 | kWh | 3.195 ¢ | $626,108 | 3.195 ¢ | $626,108 |
| **Total** | 38,572,600 | 38,572,600 | 36,802,988 | kWh | | $3,849,871 | | $4,580,530 |
| | | | | | | | Change | $730,659 |
| **Schedule No. 47/747 - Composite** | | | | | | | | |
| **Large General Service - Partial Requirement (Transmission)** | | | | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kW of on-peak demand | 69,839 | 69,839 | 57,787 | kW | $3.11 | $179,718 | $3.12 | $180,295 |
| credit per kW of on-peak demand (OATT) | 0 | 0 | 0 | kW | ($3.11) | $0 | ($3.12) | $0 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 6,633,968 | 6,633,968 | 6,144,492 | kWh | 0.065 ¢ | $3,994 | 0.057 ¢ | $3,502 |
| T&A and Sch 201 related, per kWh | 6,633,968 | 6,633,968 | 6,144,492 | kWh | 0.091 ¢ | $5,591 | 0.108 ¢ | $6,636 |
| **Distribution Charge** | | | | | | | | |
| Basic Charge | | | | | | | | |
| Facility Capacity ≤ 4,000 kW, per month | 24 | 24 | 24 | bill | $710.00 | $17,040 | $1,740.00 | $41,760 |
| Facility Capacity > 4,000 kW, per month | 24 | 24 | 24 | bill | $1,820.00 | $43,680 | $4,460.00 | $107,040 |
| Facilities Charge | | | | | | | | |
| Facility Capacity ≤ 4,000 kW, per kW | 29,508 | 29,508 | 28,154 | kW | $1.25 | $35,193 | $1.35 | $38,008 |
| Facility Capacity > 4,000 kW, per kW | 201,492 | 201,492 | 168,755 | kW | $1.05 | $177,193 | $1.15 | $194,068 |
| Demand Charge, per kW of on-peak demand | 69,839 | 69,839 | 57,787 | kW | $1.85 | $106,906 | $6.06 | $350,189 |
| Reactive Power Charge, per kvar | 42,521 | 42,521 | 33,459 | kvar | 55.00 ¢ | $18,402 | 55.00 ¢ | $18,402 |
| Reactive Hours, per kvarh | 5,610,565 | 5,610,565 | 4,314,591 | kvarh | 0.080 ¢ | $3,452 | 0.080 ¢ | $3,452 |
| Reserves Charges | | | | | | | | |
| Spinning Reserves, per kW of Facility Cap. | 231,000 | 231,000 | 196,909 | kW | $0.27 | $53,165 | $0.27 | $53,165 |
| Supplemental Reserves, per kW of Facility Cap. | 231,000 | 231,000 | 196,909 | kW | $0.27 | $53,165 | $0.27 | $53,165 |
| Spinning Reserves Credit, per kW of Facility Cap. | 0 | 0 | 0 | kW | ($0.27) | $0 | ($0.27) | $0 |
| Supplemental Reserves Credit, per kW Facil. Cap. | 0 | 0 | 0 | kW | ($0.27) | $0 | ($0.27) | $0 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| Demand Charge, per kW of On-Peak demand | 69,839 | 69,839 | 57,787 | kW | $1.68 | $97,082 | $1.45 | $83,791 |
| On-Peak, per on-peak kWh | 2,353,417 | 2,353,417 | 2,171,379 | kWh | 2.077 ¢ | $45,100 | 1.793 ¢ | $38,933 |
| Off-Peak, per off-peak kWh | 4,280,551 | 4,280,551 | 3,973,113 | kWh | 2.077 ¢ | $82,522 | 1.793 ¢ | $71,238 |
| **Unscheduled Energy, per kWh** | 463,281 | 463,281 | 431,196 | kWh | | $60,119 | | $60,119 |
| **Subtotal** | 7,097,249 | 7,097,249 | 6,575,688 | kWh | | $982,322 | | $1,303,763 |
| Renewable Adjustment Clause (202), per kWh | 7,097,249 | 7,097,249 | 6,575,688 | kWh | 0.017 ¢ | $1,118 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 7,097,249 | 7,097,249 | 6,575,688 | kWh | 0.000 ¢ | $0 | 0.224 ¢ | $14,730 |
| **Subtotal** | | | | | | $983,440 | | $1,318,493 |
| Schedule 201 | | | | | | | | |
| On-Peak, per on-peak kWh | 2,353,417 | 2,353,417 | 2,171,379 | kWh | 4.358 ¢ | $94,629 | 4.358 ¢ | $94,629 |
| Off-Peak, per off-peak kWh | 4,280,551 | 4,280,551 | 3,973,113 | kWh | 3.031 ¢ | $120,425 | 3.031 ¢ | $120,425 |
| **Total** | 7,097,249 | 7,097,249 | 6,575,688 | kWh | | $1,198,494 | | $1,533,547 |
| | | | | | | | Change | $335,053 |
| **Schedule No. 76R/776R** | | | | | | | | |
| **Large General Service/Partial Requirements Service - Economic Replacement Power Rider** | | | | | | | | |
| Transmission & Ancillary Services Charge, per kW of Daily ERP On-Peak Demand | | | | | | | | |
| Secondary | 0 | 0 | 0 | kW | $0.087 | $0 | $0.081 | $0 |
| Primary | 0 | 0 | 0 | kW | $0.095 | $0 | $0.106 | $0 |
| Transmission | 0 | 0 | 0 | kW | $0.121 | $0 | $0.122 | $0 |
| Daily ERP Demand Charge, per kW of Daily ERP On-Peak Demand | | | | | | | | |
| Secondary | 0 | 0 | 0 | kW | $0.128 | $0 | $0.244 | $0 |
| Primary | 0 | 0 | 0 | kW | $0.135 | $0 | $0.303 | $0 |
| Transmission | 0 | 0 | 0 | kW | $0.072 | $0 | $0.236 | $0 |

**PACIFIC POWER**
**State of Oregon**
**Billing Determinants**
**Actual 12 Months Ended June 30, 2023**
**Forecast 12 Months Ended December 31, 2025**

| Schedule | Actual 7/22-6/23 Units | Normalized 7/22-6/23 Units | Forecast 1/25 - 12/25 Units | | Present Price | Present Dollars | Proposed Price | Proposed Dollars |
|---|---|---|---|---|---|---|---|---|
| **Schedule No. 48/748 - Composite** | | | | | | | | |
| **Large General Service (Secondary)** | | | | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kW of on-peak demand | 1,357,579 | 1,357,579 | 1,456,129 | kW | $2.78 | $4,048,039 | $2.61 | $3,800,497 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 571,527,962 | 534,576,675 | 570,907,617 | kWh | 0.070 ¢ | $399,635 | 0.062 ¢ | $353,963 |
| T&A and Sch 201 related, per kWh | 571,527,962 | 534,576,675 | 570,907,617 | kWh | 0.100 ¢ | $570,908 | 0.121 ¢ | $690,798 |
| **Distribution Charge** | | | | | | | | |
| Basic Charge | | | | | | | | |
| Facility Capacity ≤ 4,000 kW, per month | 967 | 967 | 979 | bill | $580.00 | $567,820 | $810.00 | $792,990 |
| Facility Capacity > 4,000 kW, per month | 47 | 47 | 48 | bill | $1,600.00 | $76,800 | $2,230.00 | $107,040 |
| Facilities Charge | | | | | | | | |
| Facility Capacity ≤ 4,000 kW, per kW | 1,366,564 | 1,366,564 | 1,474,868 | kW | $2.95 | $4,350,861 | $2.65 | $3,908,400 |
| Facility Capacity > 4,000 kW, per kW | 321,484 | 321,484 | 351,447 | kW | $1.15 | $404,164 | $1.00 | $351,447 |
| Demand Charge, per kW of on-peak demand | 1,357,579 | 1,357,579 | 1,456,129 | kW | $3.28 | $4,776,103 | $6.27 | $9,129,929 |
| Reactive Power Charge, per kvar | 357,661 | 357,661 | 367,191 | kvar | 65.00 ¢ | $238,674 | 65.00 ¢ | $238,674 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| Demand Charge, per kW of On-Peak demand | 1,357,579 | 1,357,579 | 1,456,129 | kW | $1.57 | $2,286,123 | $1.37 | $1,994,897 |
| On-Peak, per on-peak kWh | 218,180,840 | 203,881,840 | 218,085,760 | kWh | 2.154 ¢ | $4,697,567 | 1.871 ¢ | $4,080,385 |
| Off-Peak, per off-peak kWh | 353,347,122 | 330,694,835 | 352,821,857 | kWh | 2.154 ¢ | $7,599,783 | 1.871 ¢ | $6,601,297 |
| **Subtotal** | 571,527,962 | 534,576,675 | 570,907,617 | kWh | | $30,016,477 | | $32,050,317 |
| Renewable Adjustment Clause (202), per kWh | 571,527,962 | 534,576,675 | 570,907,617 | kWh | 0.017 ¢ | $97,054 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 571,527,962 | 534,576,675 | 570,907,617 | kWh | 0.000 ¢ | $0 | 0.224 ¢ | $1,278,833 |
| **Subtotal** | | | | | | $30,113,531 | | $33,329,150 |
| Schedule 201 | | | | | | | | |
| On-Peak, per on-peak kWh | 218,180,840 | 203,881,840 | 218,085,760 | kWh | 4.625 ¢ | $10,086,466 | 4.625 ¢ | $10,086,466 |
| Off-Peak, per off-peak kWh | 353,347,122 | 330,694,835 | 352,821,857 | kWh | 3.333 ¢ | $11,759,552 | 3.333 ¢ | $11,759,552 |
| **Total** | 571,527,962 | 534,576,675 | 570,907,617 | kWh | | $51,959,549 | | $55,175,168 |
| | | | | | | | Change | $3,215,619 |
| **Schedule No. 48/748 - Composite** | | | | | | | | |
| **Large General Service (Primary)** | | | | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kW of on-peak demand | 2,868,329 | 2,868,329 | 4,143,758 | kW | $2.99 | $12,389,836 | $3.27 | $13,550,089 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 1,349,307,157 | 1,346,524,569 | 2,171,322,968 | kWh | 0.067 ¢ | $1,454,786 | 0.058 ¢ | $1,259,367 |
| T&A and Sch 201 related, per kWh | 1,349,307,157 | 1,346,524,569 | 2,171,322,968 | kWh | 0.096 ¢ | $2,084,470 | 0.112 ¢ | $2,431,882 |
| **Distribution Charge** | | | | | | | | |
| Basic Charge | | | | | | | | |
| Facility Capacity ≤ 4,000 kW, per month | 692 | 692 | 701 | bill | $570.00 | $399,570 | $1,140.00 | $799,140 |
| Facility Capacity > 4,000 kW, per month | 294 | 294 | 305 | bill | $1,570.00 | $478,850 | $3,130.00 | $954,650 |
| Facilities Charge | | | | | | | | |
| Facility Capacity ≤ 4,000 kW, per kW | 1,405,842 | 1,405,842 | 1,520,080 | kW | $1.25 | $1,900,100 | $1.35 | $2,052,108 |
| Facility Capacity > 4,000 kW, per kW | 2,137,522 | 2,137,522 | 3,334,729 | kW | $0.50 | $1,667,365 | $0.55 | $1,834,101 |
| Demand Charge, per kW of on-peak demand | 2,868,329 | 2,868,329 | 4,143,758 | kW | $3.46 | $14,337,403 | $7.77 | $32,197,000 |
| Reactive Power Charge, per kvar | 649,927 | 649,927 | 644,775 | kvar | 60.00 ¢ | $386,865 | 60.00 ¢ | $386,865 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| Demand Charge, per kW of On-Peak demand | 2,868,329 | 2,868,329 | 4,143,758 | kW | $1.65 | $6,837,201 | $1.44 | $5,967,012 |
| On-Peak, per on-peak kWh | 513,849,467 | 512,824,467 | 822,791,267 | kWh | 2.156 ¢ | $17,739,380 | 1.877 ¢ | $15,443,792 |
| Off-Peak, per off-peak kWh | 835,457,690 | 833,700,102 | 1,348,531,701 | kWh | 2.156 ¢ | $29,074,343 | 1.877 ¢ | $25,311,940 |
| **Subtotal** | 1,349,307,157 | 1,346,524,569 | 2,171,322,968 | kWh | | $88,750,169 | | $102,187,946 |
| Renewable Adjustment Clause (202), per kWh | 1,349,307,157 | 1,346,524,569 | 2,171,322,968 | kWh | 0.017 ¢ | $369,125 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 1,349,307,157 | 1,346,524,569 | 2,171,322,968 | kWh | 0.000 ¢ | $0 | 0.224 ¢ | $4,863,763 |
| **Subtotal** | | | | | | $89,119,294 | | $107,051,709 |
| Schedule 201 | | | | | | | | |
| On-Peak, per on-peak kWh | 513,849,467 | 512,824,467 | 822,791,267 | kWh | 4.500 ¢ | $37,025,607 | 4.500 ¢ | $37,025,607 |
| Off-Peak, per off-peak kWh | 835,457,690 | 833,700,102 | 1,348,531,701 | kWh | 3.195 ¢ | $43,085,588 | 3.195 ¢ | $43,085,588 |
| **Total** | 1,349,307,157 | 1,346,524,569 | 2,171,322,968 | kWh | | $169,230,489 | | $187,162,904 |
| | | | | | | | Change | $17,932,415 |
| **Schedule No. 48/748 - Composite** | | | | | | | | |
| **Large General Service (Transmission)** | | | | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kW of on-peak demand | 1,765,230 | 1,765,230 | 2,942,058 | kW | $3.65 | $10,738,512 | $3.66 | $10,767,932 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 1,156,897,000 | 1,156,897,000 | 1,934,879,950 | kWh | 0.065 ¢ | $1,257,672 | 0.057 ¢ | $1,102,882 |
| T&A and Sch 201 related, per kWh | 1,156,897,000 | 1,156,897,000 | 1,934,879,950 | kWh | 0.091 ¢ | $1,760,741 | 0.108 ¢ | $2,089,670 |
| **Distribution Charge** | | | | | | | | |
| Basic Charge | | | | | | | | |
| Facility Capacity ≤ 4,000 kW, per month | 23 | 23 | 24 | bill | $710.00 | $17,040 | $1,740.00 | $41,760 |
| Facility Capacity > 4,000 kW, per month | 60 | 60 | 60 | bill | $1,820.00 | $109,200 | $4,460.00 | $267,600 |
| Facilities Charge | | | | | | | | |
| Facility Capacity ≤ 4,000 kW, per kW | 22,357 | 22,357 | 26,522 | kW | $1.25 | $33,153 | $1.35 | $35,805 |
| Facility Capacity > 4,000 kW, per kW | 1,855,595 | 1,855,595 | 3,095,875 | kW | $1.05 | $3,250,669 | $1.15 | $3,560,256 |
| Demand Charge, per kW of on-peak demand | 1,765,230 | 1,765,230 | 2,942,058 | kW | $1.85 | $5,442,807 | $6.06 | $17,828,871 |
| Reactive Power Charge, per kvar | 45,999 | 45,999 | 54,046 | kvar | 55.00 ¢ | $29,725 | 55.00 ¢ | $29,725 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| Demand Charge, per kW of On-Peak demand | 1,765,230 | 1,765,230 | 2,942,058 | kW | $1.68 | $4,942,657 | $1.45 | $4,265,984 |
| On-Peak, per on-peak kWh | 433,489,000 | 433,489,000 | 725,013,625 | kWh | 2.077 ¢ | $15,058,533 | 1.793 ¢ | $12,999,494 |
| Off-Peak, per off-peak kWh | 723,408,000 | 723,408,000 | 1,209,866,325 | kWh | 2.077 ¢ | $25,128,924 | 1.793 ¢ | $21,692,903 |
| **Subtotal** | 1,156,897,000 | 1,156,897,000 | 1,934,879,950 | kWh | | $67,769,633 | | $74,682,882 |
| Renewable Adjustment Clause (202), per kWh | 1,156,897,000 | 1,156,897,000 | 1,934,879,950 | kWh | 0.017 ¢ | $328,930 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 1,156,897,000 | 1,156,897,000 | 1,934,879,950 | kWh | 0.000 ¢ | $0 | 0.224 ¢ | $4,334,131 |
| **Subtotal** | | | | | | $68,098,563 | | $79,017,013 |
| Schedule 201 | | | | | | | | |
| On-Peak, per on-peak kWh | 433,489,000 | 433,489,000 | 725,013,625 | kWh | 4.358 ¢ | $31,596,094 | 4.358 ¢ | $31,596,094 |
| Off-Peak, per off-peak kWh | 723,408,000 | 723,408,000 | 1,209,866,325 | kWh | 3.031 ¢ | $36,671,048 | 3.031 ¢ | $36,671,048 |
| **Total** | 1,156,897,000 | 1,156,897,000 | 1,934,879,950 | kWh | | $136,365,705 | | $147,284,155 |
| | | | | | | | Change | $10,918,450 |

**PACIFIC POWER**
**State of Oregon**
**Billing Determinants**
**Actual 12 Months Ended June 30, 2023**
**Forecast 12 Months Ended December 31, 2025**

| Schedule | Actual 7/22-6/23 Units | Normalized 7/22-6/23 Units | Forecast 1/25 - 12/25 Units | | Present Price | Present Dollars | Proposed Price | Proposed Dollars |
|---|---|---|---|---|---|---|---|---|
| **Schedule No. 848 - Commercial** | | | | | | | | |
| **Distribution Only Large General Service (Transmission)** | | | | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kW of on-peak demand | | | | kW | | | | |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | | | | kWh | | | | |
| T&A and Sch 201 related, per kWh | | | | kWh | | | | |
| **Distribution Charge** | | | | | | | | |
| Basic Charge | | | | | | | | |
| Facility Capacity ≤ 4,000 kW, per month | 0 | 0 | 0 | bill | $710.00 | $0 | $1,740.00 | $0 |
| Facility Capacity > 4,000 kW, per month | 12 | 12 | 12 | bill | $1,820.00 | $21,840 | $4,460.00 | $53,520 |
| Facilities Charge | | | | | | | | |
| Facility Capacity ≤ 4,000 kW, per kW | 0 | 0 | 0 | kW | $1.25 | $0 | $1.35 | $0 |
| Facility Capacity > 4,000 kW, per kW | 396,113 | 396,113 | 524,299 | kW | $1.05 | $550,514 | $1.15 | $602,944 |
| Demand Charge, per kW of on-peak demand | 385,893 | 385,893 | 510,772 | kW | $1.85 | $944,928 | $6.06 | $3,095,278 |
| Reactive Power Charge, per kvar | 0 | 0 | 0 | kvar | 55.00 ¢ | $0 | 55.00 ¢ | $0 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| Demand Charge, per kW of On-Peak demand | | | | kW | | | | |
| On-Peak, per on-peak kWh | | | | kWh | | | | |
| Off-Peak, per off-peak kWh | | | | kWh | | | | |
| **Subtotal** | | | | kWh | | $1,517,282 | | $3,751,742 |
| Renewable Adjustment Clause (202), per kWh | | | | | | | | |
| Insurance Premium Adder- Base (80), per kWh | *269,239,000* | *269,239,000* | *335,577,000* | kWh | 0.000 ¢ | $0 | 0.224 ¢ | $751,692 |
| **Subtotal** | | | | | | $1,517,282 | | $4,503,434 |
| Schedule 201 | | | | | | | | |
| On-Peak, per on-peak kWh | | | | kWh | | | | |
| Off-Peak, per off-peak kWh | | | | kWh | | | | |
| **Total** | | | | kWh | | $1,517,282 | | $4,503,434 |
| Energy Delivered | 269,239,000 | 269,239,000 | 335,577,000 | | | | Change | $2,986,152 |
| **Schedule No. 15 - Composite** | | | | | | | | |
| **Outdoor Area Lighting Service** | | | | | | | | |
| No. of Customers | 5,991 | 5,991 | 5,833 | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kWh | 8,258,382 | 8,258,382 | 8,156,574 | kWh | 0.066 ¢ | $5,394 | 0.040 ¢ | $3,298 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 8,258,382 | 8,258,382 | 8,156,574 | kWh | 0.026 ¢ | $2,143 | 0.015 ¢ | $1,202 |
| T&A and Sch 201 related, per kWh | 8,258,382 | 8,258,382 | 8,156,574 | kWh | 0.029 ¢ | $2,357 | 0.029 ¢ | $2,403 |
| **Distribution Charge** | | | | | | | | |
| Distribution Charge, per kWh | 8,258,382 | 8,258,382 | 8,156,574 | kWh | 7.857 ¢ | $638,246 | 8.707 ¢ | $710,183 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| per kWh | 8,258,382 | 8,258,382 | 8,156,574 | kWh | 0.962 ¢ | $78,307 | 0.659 ¢ | $53,776 |
| **Subtotal** | 8,258,382 | 8,258,382 | 8,156,574 | kWh | | $726,447 | | $770,863 |
| Renewable Adjustment Clause (202), per kWh | 8,258,382 | 8,258,382 | 8,156,574 | kWh | 0.014 ¢ | $1,142 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 2,159,285 | 2,159,285 | 2,127,947 | kWh | 0.000 ¢ | $0 | 0.621 ¢ | $13,215 |
| **Subtotal** | | | | | | $727,589 | | $784,078 |
| Schedule 201 | | | | | | | | |
| per kWh | 8,258,382 | 8,258,382 | 8,156,574 | kWh | 1.374 ¢ | $111,792 | 1.371 ¢ | $111,792 |
| **Total** | 8,258,382 | 8,258,382 | 8,156,574 | kWh | | $839,381 | | $895,869 |
| | | | | | | | Change | $56,488 |
| **Schedule No. 51/751** | | | | | | | | |
| **Street Lighting Service, Company-Owned System** | | | | | | | | |
| No. of Customers | 1,194 | 1,194 | 1,210 | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kWh | 23,584,283 | 23,584,283 | 20,858,198 | kWh | 0.084 ¢ | $17,569 | 0.057 ¢ | $11,816 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 23,584,283 | 23,584,283 | 20,858,198 | kWh | 0.032 ¢ | $6,696 | 0.028 ¢ | $5,887 |
| T&A and Sch 201 related, per kWh | 23,584,283 | 23,584,283 | 20,858,198 | kWh | 0.047 ¢ | $9,836 | 0.047 ¢ | $9,702 |
| **Distribution Charge** | | | | | | | | |
| Distribution Charge, per kWh | 23,584,283 | 23,584,283 | 20,858,198 | kWh | 10.691 ¢ | $2,229,901 | 11.922 ¢ | $2,486,734 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| per kWh | 23,584,283 | 23,584,283 | 20,858,198 | kWh | 1.352 ¢ | $281,955 | 0.904 ¢ | $188,486 |
| **Subtotal** | 23,584,283 | 23,584,283 | 20,858,198 | kWh | | $2,545,957 | | $2,702,626 |
| Renewable Adjustment Clause (202), per kWh | 23,584,283 | 23,584,283 | 20,858,198 | kWh | 0.014 ¢ | $2,920 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 8,930,279 | 8,930,279 | 7,898,066 | kWh | 0.000 ¢ | $0 | 0.621 ¢ | $49,047 |
| **Subtotal** | | | | | | $2,548,877 | | $2,751,673 |
| Schedule 201 | | | | | | | | |
| per kWh | 23,584,283 | 23,584,283 | 20,858,198 | kWh | 1.696 ¢ | $353,820 | 1.696 ¢ | $353,820 |
| **Total** | 0 | 0 | 20,858,198 | kWh | | $2,902,697 | | $3,105,493 |
| | | | | | | | Change | $202,796 |

**PACIFIC POWER**
**State of Oregon**
**Billing Determinants**
**Actual 12 Months Ended June 30, 2023**
**Forecast 12 Months Ended December 31, 2025**

| Schedule | Actual 7/22-6/23 Units | Normalized 7/22-6/23 Units | Forecast 1/25 - 12/25 Units | | Present Price | Present Dollars | Proposed Price | Proposed Dollars |
|---|---|---|---|---|---|---|---|---|
| **Schedule No. 53/753** | | | | | | | | |
| **Street Lighting Service, Consumer-Owned System** | | | | | | | | |
| No. of Customers | 294 | 294 | 296 | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kWh | 8,075,045 | 8,075,045 | 8,821,260 | kWh | 0.029 ¢ | $2,558 | 0.021 ¢ | $1,852 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 8,075,045 | 8,075,045 | 8,821,260 | kWh | 0.012 ¢ | $1,059 | 0.009 ¢ | $794 |
| T&A and Sch 201 related, per kWh | 8,075,045 | 8,075,045 | 8,821,260 | kWh | 0.015 ¢ | $1,323 | 0.015 ¢ | $1,323 |
| **Distribution Charge** | | | | | | | | |
| Distribution Charge, per kWh | 8,075,045 | 8,075,045 | 8,821,260 | kWh | 4.262 ¢ | $324,469 | 4.095 ¢ | $361,253 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| per kWh | 8,075,045 | 8,075,045 | 8,821,260 | kWh | 0.449 ¢ | $39,607 | 0.310 ¢ | $27,346 |
| **Subtotal** | 8,075,045 | 8,075,045 | 8,821,260 | kWh | | $369,016 | | $392,569 |
| Renewable Adjustment Clause (202), per kWh | 8,075,045 | 8,075,045 | 8,821,260 | kWh | 0.014 ¢ | $1,235 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 8,075,045 | 8,075,045 | 8,821,260 | kWh | 0.000 ¢ | $0 | 0.621 ¢ | $54,780 |
| **Subtotal** | | | | | | $370,251 | | $447,349 |
| Schedule 201 | | | | | | | | |
| per kWh | 8,075,045 | 8,075,045 | 8,821,260 | kWh | 1.320 ¢ | $116,441 | 1.320 ¢ | $116,441 |
| **Total** | 8,075,045 | 8,075,045 | 8,821,260 | kWh | | $486,692 | | $563,790 |
| | | | | | | | Change | $77,098 |
| **Schedule No. 54/754** | | | | | | | | |
| **Recreational Field Lighting** | | | | | | | | |
| **Transmission & Ancillary Services Charge** | | | | | | | | |
| per kWh | 1,449,879 | 1,449,879 | 1,373,662 | kWh | 0.037 ¢ | $508 | 0.026 ¢ | $357 |
| **System Usage Charge** | | | | | | | | |
| Sch 200 related, per kWh | 1,449,879 | 1,449,879 | 1,373,662 | kWh | 0.016 ¢ | $220 | 0.011 ¢ | $151 |
| T&A and Sch 201 related, per kWh | 1,449,879 | 1,449,879 | 1,373,662 | kWh | 0.020 ¢ | $275 | 0.019 ¢ | $261 |
| **Distribution Charge** | | | | | | | | |
| Basic Charge, Single Phase, per month | 759 | 759 | 757 | bill | $6.00 | $4,542 | $6.00 | $4,542 |
| Basic Charge, Three Phase, per month | 420 | 420 | 419 | bill | $9.00 | $3,771 | $9.00 | $3,771 |
| Distribution Energy Charge, per kWh | 1,449,879 | 1,449,879 | 1,373,662 | kWh | 4.001 ¢ | $54,960 | 4.537 ¢ | $62,323 |
| **Energy Charge - Schedule 200** | | | | | | | | |
| per kWh | 1,449,879 | 1,449,879 | 1,373,662 | kWh | 0.578 ¢ | $7,940 | 0.390 ¢ | $5,357 |
| **Subtotal** | 1,449,879 | 1,449,879 | 1,373,662 | kWh | | $72,216 | | $76,762 |
| Renewable Adjustment Clause (202), per kWh | 1,449,879 | 1,449,879 | 1,373,662 | kWh | 0.014 ¢ | $192 | 0.000 ¢ | $0 |
| Insurance Premium Adder- Base (80), per kWh | 1,449,879 | 1,449,879 | 1,373,662 | kWh | 0.000 ¢ | $0 | 0.621 ¢ | $8,530 |
| **Subtotal** | | | | | | $72,408 | | $85,292 |
| Schedule 201 | | | | | | | | |
| per kWh | 1,449,879 | 1,449,879 | 1,373,662 | kWh | 1.320 ¢ | $18,132 | 1.320 ¢ | $18,132 |
| **Total** | 1,449,879 | 1,449,879 | 1,373,662 | kWh | | $90,540 | | $103,424 |
| | | | | | | | Change | $12,884 |
| **Subtotal Oregon** | 14,132,701,620 | 13,680,122,990 | 15,339,351,516 | | | $1,677,396,895 | | $1,855,533,708 |
| Employee Discount | | | | | | ($445,083) | | ($493,289) |
| **TOTAL OREGON** | **14,132,701,620** | **13,680,122,990** | **15,339,351,516** | | | **$1,676,951,812** | | **$1,855,040,419** |
| Distribution Only Energy | 269,239,000 | 269,239,000 | 335,577,000 | | | | | |
| Total Energy Including Distribution Only | 14,401,940,620 | 13,949,361,990 | 15,674,928,516 | | | | | |

**PACIFIC POWER**
**STATE OF OREGON**
**Calculation of Proposed Insurance Cost Adjustment - Schedule 80**

**FORECAST 12 MONTHS ENDED DECEMBER 31, 2025**

| Line No. | Description | Sch No. | MWh* | Proposed Base Revenues** ($000) | Equal Percentage Rate Spread | Proposed Schedule 80 Base Rates (¢/kWh) | Base Revenues ($000) | Deferred Rates (¢/kWh) | Deferred Revenues ($000) |
|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
| | **Residential** | | | | | | | | |
| 1 | Residential | 4 | 5,787,620 | $850,079 | 47.4% | 0.406 | $23,498 | 0.125 | $7,235 |
| 2 | **Total Residential** | | 5,787,620 | $850,079 | | | $23,498 | | $7,235 |
| | **Commercial & Industrial** | | | | | | | | |
| 3 | Gen. Svc. < 31 kW | 23 | 1,162,132 | $176,506 | 9.8% | 0.420 | $4,881 | 0.129 | $1,499 |
| 4 | Gen. Svc. 31 - 200 kW | 28 | 2,064,712 | $220,378 | 12.3% | 0.295 | $6,091 | 0.091 | $1,879 |
| 5 | Gen. Svc. 201 - 999 kW | 30 | 1,330,279 | $126,675 | 7.1% | 0.263 | $3,499 | 0.081 | $1,078 |
| 6 | Large General Service >= 1,000 kW | 48 | 4,677,111 | $379,146 | 21.1% | 0.224 | $10,477 | 0.069 | $3,227 |
| 7 | Partial Req. Svc. >= 1,000 kW | 47 | 43,379 | $6,017 | | 0.224 | $97 | 0.069 | $30 |
| 8 | Dist. Only Lg Gen Svc >= 1,000 kW | 848 | 335,577 | $3,752 | | 0.224 | $752 | 0.069 | $232 |
| 9 | Agricultural Pumping Service | 41 | 234,910 | $37,971 | 2.1% | 0.446 | $1,048 | 0.138 | $324 |
| 10 | **Total Commercial & Industrial** | | 9,848,099 | $950,444 | | | $26,844 | | $8,268 |
| | **Lighting** | | | | | | | | |
| 11 | Outdoor Area Lighting Service | 15 | 2,128 | $883 | | 0.621 | $13 | 0.192 | $4 |
| 12 | Street Lighting Service Comp. Owned | 51 | 7,898 | $3,056 | | 0.621 | $49 | 0.192 | $15 |
| 13 | Street Lighting Service Cust. Owned | 53 | 8,821 | $509 | | 0.621 | $55 | 0.192 | $17 |
| 14 | Recreational Field Lighting | 54 | 1,374 | $95 | | 0.621 | $9 | 0.192 | $3 |
| 15 | **Total Lighting** | | 20,221 | $4,543 | 0.3% | 0.621 | $126 | 0.192 | $39 |
| 16 | **Subtotal** | | 15,655,940 | $1,805,067 | 100.0% | | $50,467 | | $15,542 |
| 17 | Emplolyee Discount | | | ($480) | | | ($14) | | ($4) |
| 18 | **Total Sales with Employee Discount** | | | $1,804,587 | | | $50,454 | | $15,538 |

* Includes Distribution Only consumer MWh and lighting tariff MWh
** Proposed Base Revenues prior to inclusion of base Insurance Premium Adder

**PACIFIC POWER**
**STATE OF OREGON**
**Calculation of Proposed Addition to Wildfire Mitigation Plan Cost Recovery Adjustment - Schedule 190**

**FORECAST 12 MONTHS ENDED DECEMBER 31, 2025**

| Line No. | Description | Sch No. | MWh* | Proposed Distribution Revenues ($000) | Distribution Rate Spread | Proposed Schedule 190 Addition Rate (¢/kWh) | Proposed Schedule 190 Addition Revenues ($000) | Total Proposed 190 Rate (¢/kWh) |
|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
| | **Residential** | | | | | | | |
| 1 | Residential | 4 | 5,787,620 | $400,381 | 57.1% | 0.210 | $12,154 | 0.679 |
| 2 | **Total Residential** | | 5,787,620 | $400,381 | | | $12,154 | |
| | **Commercial & Industrial** | | | | | | | |
| 3 | Gen. Svc. < 31 kW | 23 | 1,162,132 | $88,708 | 12.7% | 0.231 | $2,685 | 0.757 |
| 4 | Gen. Svc. 31 - 200 kW | 28 | 2,064,712 | $72,307 | 10.3% | 0.106 | $2,189 | 0.308 |
| 5 | Gen. Svc. 201 - 999 kW | 30 | 1,330,279 | $33,201 | 4.7% | 0.076 | $1,011 | 0.211 |
| 6 | Large General Service >= 1,000 kW | 48 | 4,677,111 | $74,516 | | 0.048 | $2,245 | 0.133 |
| 7 | Partial Req. Svc. >= 1,000 kW | 47 | 43,379 | $2,422 | 11.5% | 0.048 | $21 | 0.133 |
| 8 | Dist. Only Lg Gen Svc >= 1,000 kW | 848 | 335,577 | $3,752 | | 0.048 | $161 | 0.133 |
| 9 | Agricultural Pumping Service | 41 | 234,910 | $21,908 | 3.1% | 0.283 | $665 | 0.839 |
| 10 | **Total Commercial & Industrial** | | 9,848,099 | $296,813 | | | $8,976 | |
| | **Lighting** | | | | | | | |
| 11 | Outdoor Area Lighting Service | 15 | 2,128 | $710 | 0.1% | 1.011 | $22 | 3.600 |
| 12 | Street Lighting Service Comp. Owned | 51 | 7,898 | $2,487 | 0.4% | 0.954 | $75 | 3.469 |
| 13 | Street Lighting Service Cust. Owned | 53 | 8,821 | $361 | 0.1% | 0.124 | $11 | 0.441 |
| 14 | Recreational Field Lighting | 54 | 1,374 | $71 | 0.0% | 0.156 | $2 | 0.551 |
| 15 | **Total Lighting** | | 20,221 | $3,629 | | | $110 | |
| 16 | **Subtotal** | | 15,655,940 | $700,824 | 100.0% | | $21,240 | |
| 17 | Emplolyee Discount | | | ($220) | | | ($7) | |
| 18 | **Total Sales with Employee Discount** | | | $700,603 | | | $21,233 | |

* Includes Distribution Only consumer MWh and lighting tariff MWh

Docket No. UE 433
Exhibit PAC/3507
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Robert M. Meredith**

**Updated Estimated Effect of Proposed Rates and Proposed Adjustment Schedules**

**July 2024**

**PACIFIC POWER**
**ESTIMATED EFFECT OF PROPOSED PRICE CHANGE**
**ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS**
**DISTRIBUTED BY RATE SCHEDULES IN OREGON**
**FORECAST 12 MONTHS ENDED DECEMBER 31, 2025**

| Line No. | Description | Sch No. | No. of Cust | MWh | Present Revenues ($000) Base Rates | Present Revenues ($000) Adders[1] | Present Revenues ($000) Net Rates | Proposed Revenues ($000) Base Rates | Proposed Revenues ($000) Adders[1] | Proposed Revenues ($000) Net Rates | Change Base Rates ($000) | Change Base Rates %[2] | Change Net Rates ($000) | Change Net Rates %[2] | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | |
| | | | | | | | (5) + (6) | | | (8) + (9) | (8) - (5) | (11)/(5) | (10) - (7) | (13)/(7) | |
| | **Residential** | | | | | | | | | | | | | | |
| 1 | Residential | 4 | 513,581 | 5,787,620 | $786,075 | $45,954 | $832,029 | $873,577 | $82,821 | $956,398 | $87,502 | 11.1% | $124,369 | 14.9% | 1 |
| 2 | **Total Residential** | | 513,581 | 5,787,620 | $786,075 | $45,954 | $832,029 | $873,577 | $82,821 | $956,398 | $87,502 | 11.1% | $124,369 | 14.9% | 2 |
| | **Commercial & Industrial** | | | | | | | | | | | | | | |
| 3 | Gen. Svc. < 31 kW | 23 | 86,033 | 1,162,132 | $159,887 | $10,366 | $170,253 | $181,387 | $14,271 | $195,658 | $21,500 | 13.4% | $25,405 | 14.9% | 3 |
| 4 | Gen. Svc. 31 - 200 kW | 28 | 10,658 | 2,064,712 | $211,334 | $25,644 | $236,978 | $226,469 | $21,287 | $247,756 | $15,135 | 7.2% | $10,778 | 4.5% | 4 |
| 5 | Gen. Svc. 201 - 999 kW | 30 | 847 | 1,330,279 | $118,973 | $14,740 | $133,713 | $130,173 | $11,641 | $141,814 | $11,201 | 9.4% | $8,101 | 6.1% | 5 |
| 6 | Large General Service >= 1,000 kW | 48 | 177 | 4,677,111 | $357,556 | $19,276 | $376,831 | $389,622 | $23,719 | $413,341 | $32,066 | 9.1% | $36,510 | 9.8% | 6 |
| 7 | Partial Req. Svc. >= 1,000 kW | 47 | 6 | 43,379 | $5,048 | $179 | $5,228 | $6,114 | $220 | $6,334 | $1,066 | 9.1% | $1,107 | 9.8% | 7 |
| 8 | Dist. Only Lg Gen Svc >= 1,000 kW | 848 | 1 | 0 | $1,517 | $547 | $2,064 | $4,503 | $940 | $5,443 | $2,986 | 196.8% | $3,379 | 163.7% | 8 |
| 9 | Agricultural Pumping Service | 41 | 7,884 | 234,910 | $32,687 | ($1,212) | $31,475 | $39,019 | ($2,847) | $36,171 | $6,332 | 19.4% | $4,697 | 14.9% | 9 |
| 10 | **Total Commercial & Industrial** | | 105,606 | 9,512,522 | $887,002 | $69,540 | $956,542 | $977,288 | $69,230 | $1,046,518 | $90,286 | 10.2% | $89,977 | 9.4% | 10 |
| | **Lighting** | | | | | | | | | | | | | | |
| 11 | Outdoor Area Lighting Service | 15 | 5,833 | 8,157 | $839 | $315 | $1,154 | $896 | $293 | $1,189 | $56 | 6.7% | $34 | 3.0% | 11 |
| 12 | Street Lighting Service Comp. Owned | 51 | 1,210 | 20,858 | $2,903 | $1,229 | $4,132 | $3,105 | $1,152 | $4,258 | $203 | 7.0% | $126 | 3.0% | 12 |
| 13 | Street Lighting Service Cust. Owned | 53 | 296 | 8,821 | $487 | $293 | $780 | $564 | $240 | $804 | $77 | 15.8% | $24 | 3.0% | 13 |
| 14 | Recreational Field Lighting | 54 | 98 | 1,374 | $91 | $58 | $148 | $103 | $49 | $153 | $13 | 14.2% | $4 | 3.0% | 14 |
| 15 | **Total Public Street Lighting** | | 7,437 | 39,210 | $4,319 | $1,896 | $6,215 | $4,669 | $1,734 | $6,403 | $349 | 8.1% | $188 | 3.0% | 15 |
| 16 | **Subtotal** | | 626,624 | 15,339,352 | $1,677,397 | $117,389 | $1,794,786 | $1,855,534 | $153,786 | $2,009,319 | $178,137 | 10.6% | $214,534 | 12.0% | 16 |
| 17 | Emplolyee Discount | | *867* | *13,364* | ($445) | ($27) | ($472) | ($493) | ($48) | ($541) | ($48) | | ($69) | | 17 |
| 18 | Paperless Credit | | | | ($1,855) | | ($1,855) | ($1,855) | | ($1,855) | $0 | | $0 | | 18 |
| 19 | AGA Revenue | | | | $4,071 | | $4,071 | $4,071 | | $4,071 | $0 | | $0 | | 19 |
| 20 | COOC Amortization | | | | $1,769 | | $1,769 | $1,769 | | $1,769 | $0 | | $0 | | 20 |
| 21 | **Total** | | 626,624 | 15,339,352 | $1,680,937 | $117,362 | $1,798,299 | $1,859,026 | $153,738 | $2,012,763 | $178,089 | 10.6% | $214,464 | 11.9% | 21 |

[1] Excludes effects of the low income assistance charges (Sch. 91 and Sch. 92), BPA credit (Sch. 98), Public Purpose Charge (Sch. 290) and System Benefits Charge (Sch. 291).

[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

**PACIFIC POWER**
**ESTIMATED REVENUES OF ADJUSTMENT SCHEDULES**
**FORECAST 12 MONTHS ENDED DECEMBER 31, 2025**

| Line No. | Description | Pre Sch No. | Def. Insur. 80 ($000) | WMVM Adj 94 ($000) | Prop Sls. Adj 96 ($000) | Intv. Fndg Adj 97 ($000) | WMP Def Adj 190 ($000) | WMP Def Adj 190 ($000) | Def Acct Adj 192 ($000) | Cat Wildf Adj 193 ($000) | Repl Mtr Def Adj 194 ($000) | Deer Cr Def Adj 198 ($000) | RAC Defer. 203 ($000) | Sol. Inctv. 204 ($000) | PCAM 206 ($000) | Comm. Sol 207 ($000) | RMA 299 ($000) | RMA 299 ($000) | Total ($000) | Total ($000) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) | (17) | (18) | (19) | (20) |
| | | | PRO | | | | PRE | PRO | | PRO | | | | | | | PRE | PRO | PRE | PRO |
| | **Residential** | | | | | | | | | | | | | | | | | | | |
| 1 | Residential | 4 | $7,235 | $15,684 | $1,158 | $1,794 | $27,144 | $39,298 | $3,530 | $0 | $1,910 | $868 | $3,299 | $984 | $6,598 | $695 | ($17,710) | ($232) | $45,954 | $82,821 |
| 2 | **Total Residential** | | $7,235 | $15,684 | $1,158 | $1,794 | $27,144 | $39,298 | $3,530 | $0 | $1,910 | $868 | $3,299 | $984 | $6,598 | $695 | ($17,710) | ($232) | $45,954 | $82,821 |
| | **Commercial & Industrial** | | | | | | | | | | | | | | | | | | | |
| 3 | Gen. Svc. < 31 kW | 23 | $1,499 | $3,533 | $232 | $0 | $6,113 | $8,797 | $535 | $0 | $395 | $163 | $628 | $186 | $1,255 | $139 | ($2,812) | ($3,091) | $10,366 | $14,271 |
| 4 | Gen. Svc. 31 - 200 kW | 28 | $1,879 | $2,395 | $413 | $0 | $4,171 | $6,359 | $227 | $0 | $516 | $289 | $1,094 | $330 | $2,230 | $227 | $13,751 | $5,327 | $25,644 | $21,287 |
| 5 | Gen. Svc. 201 - 999 kW | 30 | $1,078 | $1,038 | $266 | $0 | $1,796 | $2,807 | $80 | $0 | $306 | $186 | $692 | $200 | $1,411 | $146 | $8,620 | $3,432 | $14,740 | $11,641 |
| 6 | Large General Service >= 1,000 kW | 48 | $3,227 | $2,292 | $935 | $1,123 | $3,976 | $6,221 | $234 | $0 | $935 | $608 | $2,339 | $655 | $4,636 | $514 | $1,029 | $0 | $19,276 | $23,719 |
| 7 | Partial Req. Svc. >= 1,000 kW | 47 | $30 | $21 | $9 | $10 | $37 | $58 | $2 | $0 | $9 | $6 | $22 | $6 | $43 | $5 | $10 | $0 | $179 | $220 |
| 8 | Dist. Only Lg Gen Svc >= 1,000 kW | 848 | $232 | $164 | $0 | $81 | $285 | $446 | $17 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $547 | $940 |
| 9 | Agricultural Pumping Service | 41 | $324 | $754 | $47 | $0 | $1,306 | $1,971 | $42 | $0 | $82 | $33 | $122 | $35 | $242 | $26 | ($3,902) | ($6,526) | ($1,212) | ($2,847) |
| 10 | **Total Commercial & Industrial** | | $8,268 | $10,197 | $1,903 | $1,213 | $17,683 | $26,659 | $1,137 | $0 | $2,244 | $1,285 | $4,896 | $1,412 | $9,817 | $1,058 | $16,695 | ($858) | $69,540 | $69,230 |
| | **Lighting** | | | | | | | | | | | | | | | | | | | |
| 11 | Outdoor Area Lighting Service | 15 | $4 | $32 | $0 | $0 | $55 | $77 | $0 | $0 | $1 | $0 | $1 | $0 | $4 | $0 | $222 | $174 | $315 | $293 |
| 12 | Street Lighting Service Comp. Owned | 51 | $15 | $115 | $2 | $0 | $199 | $274 | $0 | $0 | $3 | $0 | $3 | $1 | $12 | $1 | $894 | $727 | $1,229 | $1,152 |
| 13 | Street Lighting Service, Cust Owned | 53 | $17 | $16 | $2 | $0 | $28 | $39 | $0 | $0 | $1 | $1 | $3 | $1 | $4 | $1 | $237 | $155 | $293 | $240 |
| 14 | Recreational Field Lighting | 54 | $3 | $3 | $0 | $0 | $5 | $8 | $0 | $0 | $0 | $0 | $1 | $0 | $1 | $0 | $47 | $34 | $58 | $49 |
| 15 | **Total Public Street Lighting** | | $39 | $166 | $4 | $0 | $287 | $397 | $0 | $0 | $6 | $1 | $8 | $2 | $20 | $2 | $1,400 | $1,090 | $1,896 | $1,734 |
| 16 | **Subtotal** | | $15,542 | $26,047 | $3,064 | $3,008 | $45,114 | $66,354 | $4,667 | $0 | $4,160 | $2,154 | $8,203 | $2,398 | $16,435 | $1,754 | $385 | $0 | $117,389 | $153,786 |
| 17 | Employee Discount | | ($4) | ($9) | ($1) | ($1) | ($16) | ($23) | ($2) | $0 | ($1) | ($1) | ($2) | ($1) | ($4) | ($0) | $10 | $0 | ($27) | ($48) |
| 18 | **Total** | | $15,538 | $26,038 | $3,063 | $3,007 | $45,099 | $66,331 | $4,665 | $0 | $4,158 | $2,153 | $8,201 | $2,398 | $16,431 | $1,754 | $395 | $0 | $117,362 | $153,738 |

**PACIFIC POWER**
**PRESENT AND PROPOSED RATES OF ADJUSTMENT SCHEDULES**
**FORECAST 12 MONTHS ENDED DECEMBER 31, 2025**

| Line No. | Description | Pre Sch No. | Def. Insur. 80 ¢/kWh | WMVM Adj 94 ¢/kWh | Prop Sls. Adj 96 ¢/kWh | Intv. Fndg Adj 97 ¢/kWh | WMP Def Adj 190 ¢/kWh | WMP Def Adj 190 ¢/kWh | Def Acct Adj 192 ¢/kWh | Cat Wildf Adj 193 ¢/kWh | Repl Mtr Def Adj 194 ¢/kWh | Deer Cr Def Adj 198 ¢/kWh | RAC Defer. 203 ¢/kWh | Sol. Inctv. 204 ¢/kWh | PCAM Sec 206 ¢/kWh | PCAM Pri 206 ¢/kWh | PCAM Trn 206 ¢/kWh | Comm. Sol 207 ¢/kWh | RMA 299 ¢/kWh | RMA 299 ¢/kWh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) | (17) | (18) | (19) |
| | | | PRO | | | | PRE | PRO | | PRO | | | | | | | | | PRE | PRO |
| | **Residential** | | | | | | | | | | | | | | | | | | | |
| 1 | Residential | 4 | 0.125 | 0.271 | 0.020 | 0.031 | 0.469 | 0.679 | 0.061 | 0.000 | 0.033 | 0.015 | 0.057 | 0.017 | 0.114 | | | 0.012 | (0.306) | (0.004) |
| | **Commercial & Industrial** | | | | | | | | | | | | | | | | | | | |
| 2 | Gen. Svc. < 31 kW | 23 | 0.129 | 0.304 | 0.020 | 0.000 | 0.526 | 0.757 | 0.046 | 0.000 | 0.034 | 0.014 | 0.054 | 0.016 | 0.108 | 0.098 | | 0.012 | (0.242) | (0.266) |
| 3 | Gen. Svc. 31 - 200 kW | 28 | 0.091 | 0.116 | 0.020 | 0.000 | 0.202 | 0.308 | 0.011 | 0.000 | 0.025 | 0.014 | 0.053 | 0.016 | 0.108 | 0.107 | | 0.011 | 0.666 | 0.258 |
| 4 | Gen. Svc. 201 - 999 kW | 30 | 0.081 | 0.078 | 0.020 | 0.000 | 0.135 | 0.211 | 0.006 | 0.000 | 0.023 | 0.014 | 0.052 | 0.015 | 0.106 | 0.107 | | 0.011 | 0.648 | 0.258 |
| 5 | Large General Service >= 1,000 kW | 48 | 0.069 | 0.049 | 0.020 | 0.024 | 0.085 | 0.133 | 0.005 | 0.000 | 0.020 | 0.013 | 0.050 | 0.014 | 0.106 | 0.101 | 0.095 | 0.011 | 0.022 | 0.000 |
| 6 | Partial Req. Svc. >= 1,000 kW | 47 | 0.069 | 0.049 | 0.020 | 0.024 | 0.085 | 0.133 | 0.005 | 0.000 | 0.020 | 0.013 | 0.050 | 0.014 | 0.106 | 0.101 | 0.095 | 0.011 | 0.022 | 0.000 |
| 7 | Dist. Only Lg Gen Svc >= 1,000 kW | 848 | 0.069 | 0.049 | 0.000 | 0.024 | 0.085 | 0.133 | 0.005 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 8 | Agricultural Pumping Service | 41 | 0.138 | 0.321 | 0.020 | 0.000 | 0.556 | 0.839 | 0.018 | 0.000 | 0.035 | 0.014 | 0.052 | 0.015 | 0.103 | 0.101 | | 0.011 | (1.661) | (2.778) |
| | **Lighting** | | | | | | | | | | | | | | | | | | | |
| 9 | Outdoor Area Lighting Service | 15 | 0.192 | 1.496 | 0.020 | 0.000 | 2.589 | 3.600 | 0.000 | 0.000 | 0.036 | 0.006 | 0.039 | 0.012 | 0.172 | | | 0.009 | 10.425 | 8.170 |
| 10 | Street Lighting Service HPS | 51 | 0.192 | 1.453 | 0.020 | 0.000 | 2.515 | 3.469 | 0.000 | 0.000 | 0.044 | 0.006 | 0.040 | 0.012 | 0.146 | | | 0.009 | 11.320 | 9.200 |
| 11 | Street Lighting Service | 53 | 0.192 | 0.183 | 0.020 | 0.000 | 0.317 | 0.441 | 0.000 | 0.000 | 0.017 | 0.006 | 0.037 | 0.012 | 0.043 | | | 0.009 | 2.682 | 1.760 |
| 12 | Recreational Field Lighting | 54 | 0.192 | 0.228 | 0.020 | 0.000 | 0.395 | 0.551 | 0.000 | 0.000 | 0.023 | 0.006 | 0.038 | 0.012 | 0.043 | | | 0.009 | 3.435 | 2.470 |

# Pacific Power
## Monthly Billing Comparison
## Delivery Service Schedule 4 + Cost-Based Supply Service
## Residential Service - Single Family

| kWh | Monthly Billing* Present Price | Monthly Billing* Proposed Price | Difference | Percent Difference |
|---|---|---|---|---|
| 100 | $25.41 | $32.21 | $6.80 | 26.76% |
| 200 | $38.63 | $47.16 | $8.53 | 22.08% |
| 300 | $51.84 | $62.09 | $10.25 | 19.77% |
| 400 | $65.06 | $77.04 | $11.98 | 18.41% |
| 500 | $78.27 | $91.98 | $13.71 | 17.52% |
| 600 | $91.48 | $106.92 | $15.44 | 16.88% |
| 700 | $104.70 | $121.86 | $17.16 | 16.39% |
| 800 | $117.91 | $136.80 | $18.89 | 16.02% |
| 900 | $131.13 | $151.75 | $20.62 | 15.72% |
| **950** | **$137.73** | **$159.22** | **$21.49** | **15.60%** |
| 1,000 | $144.34 | $166.69 | $22.35 | 15.48% |
| 1,100 | $157.55 | $181.63 | $24.08 | 15.28% |
| 1,200 | $170.77 | $196.57 | $25.80 | 15.11% |
| 1,300 | $183.98 | $211.51 | $27.53 | 14.96% |
| 1,400 | $197.20 | $226.46 | $29.26 | 14.84% |
| 1,500 | $210.41 | $241.40 | $30.99 | 14.73% |
| 1,600 | $223.62 | $256.33 | $32.71 | 14.63% |
| 2,000 | $276.48 | $316.11 | $39.63 | 14.33% |
| 3,000 | $417.38 | $474.28 | $56.90 | 13.63% |
| 4,000 | $558.28 | $632.46 | $74.18 | 13.29% |
| 5,000 | $699.19 | $790.64 | $91.45 | 13.08% |

* Net rate including Schedules 91, 92, 98, 290 and 291.

# Pacific Power
## Monthly Billing Comparison
## Delivery Service Schedule 4 + Cost-Based Supply Service
## Residential Service - Multi-Family

| kWh | Monthly Billing* Present Price | Monthly Billing* Proposed Price | Difference | Percent Difference |
|---|---|---|---|---|
| 100 | $22.36 | $25.10 | $2.74 | 12.25% |
| 200 | $35.58 | $40.05 | $4.47 | 12.56% |
| 300 | $48.79 | $54.99 | $6.20 | 12.71% |
| 400 | $62.01 | $69.94 | $7.93 | 12.79% |
| 500 | $75.22 | $84.87 | $9.65 | 12.83% |
| 600 | $88.43 | $99.81 | $11.38 | 12.87% |
| 700 | $101.65 | $114.76 | $13.11 | 12.90% |
| 800 | $114.86 | $129.70 | $14.84 | 12.92% |
| 900 | $128.08 | $144.64 | $16.56 | 12.93% |
| 950 | $134.69 | $152.11 | $17.42 | 12.93% |
| 1,000 | $141.29 | $159.58 | $18.29 | 12.95% |
| 1,100 | $154.50 | $174.52 | $20.02 | 12.96% |
| 1,200 | $167.72 | $189.47 | $21.75 | 12.97% |
| 1,300 | $180.93 | $204.41 | $23.48 | 12.98% |
| 1,400 | $194.15 | $219.35 | $25.20 | 12.98% |
| 1,500 | $207.36 | $234.29 | $26.93 | 12.99% |
| 1,600 | $220.57 | $249.23 | $28.66 | 12.99% |
| 2,000 | $273.43 | $309.00 | $35.57 | 13.01% |
| 3,000 | $414.34 | $467.18 | $52.84 | 12.75% |
| 4,000 | $555.24 | $625.36 | $70.12 | 12.63% |
| 5,000 | $696.14 | $783.53 | $87.39 | 12.55% |

* Net rate including Schedules 91, 92, 98, 290 and 291.

# Pacific Power
## Monthly Billing Comparison
## Delivery Service Schedule 23 + Cost-Based Supply Service
## General Service - Secondary Delivery Voltage

| kW Load Size | kWh | Monthly Billing* | | | | Percent Difference | |
|---|---|---|---|---|---|---|---|
| | | Present Price | | Proposed Price | | | |
| | | Single Phase | Three Phase | Single Phase | Three Phase | Single Phase | Three Phase |
| 5 | 500 | $87 | $95 | $99 | $110 | 14.56% | 15.41% |
| | 750 | $121 | $130 | $138 | $149 | 13.87% | 14.53% |
| | 1,000 | $156 | $164 | $177 | $188 | 13.47% | 14.04% |
| | 1,500 | $225 | $234 | $254 | $265 | 13.06% | 13.46% |
| 10 | 1,000 | $156 | $164 | $177 | $188 | 13.47% | 14.04% |
| | 2,000 | $294 | $303 | $332 | $342 | 12.83% | 13.15% |
| | 3,000 | $432 | $441 | $487 | $497 | 12.60% | 12.82% |
| | 4,000 | $552 | $561 | $624 | $635 | 13.05% | 13.22% |
| 20 | 4,000 | $588 | $596 | $668 | $679 | 13.72% | 13.87% |
| | 6,000 | $827 | $836 | $943 | $954 | 14.00% | 14.10% |
| | 8,000 | $1,067 | $1,075 | $1,218 | $1,228 | 14.15% | 14.23% |
| | 10,000 | $1,306 | $1,315 | $1,492 | $1,503 | 14.25% | 14.31% |
| 30 | 9,000 | $1,258 | $1,267 | $1,444 | $1,454 | 14.77% | 14.83% |
| | 12,000 | $1,617 | $1,626 | $1,856 | $1,866 | 14.74% | 14.79% |
| | 15,000 | $1,976 | $1,985 | $2,268 | $2,278 | 14.73% | 14.77% |
| | 18,000 | $2,336 | $2,344 | $2,680 | $2,690 | 14.72% | 14.76% |

* Net rate including Schedules 91, 92, 290 and 291.

# Pacific Power
## Monthly Billing Comparison
## Delivery Service Schedule 23 + Cost-Based Supply Service
## General Service - Primary Delivery Voltage

| kW Load Size | kWh | Monthly Billing* | | | | Percent Difference | |
|---|---|---|---|---|---|---|---|
| | | Present Price | | Proposed Price | | | |
| | | Single Phase | Three Phase | Single Phase | Three Phase | Single Phase | Three Phase |
| 5 | 500 | $85 | $94 | $98 | $109 | 14.70% | 15.55% |
| | 750 | $119 | $128 | $136 | $147 | 14.00% | 14.68% |
| | 1,000 | $153 | $162 | $174 | $185 | 13.61% | 14.16% |
| | 1,500 | $221 | $230 | $250 | $261 | 13.19% | 13.60% |
| 10 | 1,000 | $153 | $162 | $174 | $185 | 13.61% | 14.16% |
| | 2,000 | $289 | $297 | $326 | $337 | 12.97% | 13.29% |
| | 3,000 | $424 | $433 | $478 | $489 | 12.73% | 12.96% |
| | 4,000 | $542 | $550 | $613 | $624 | 13.18% | 13.35% |
| 20 | 4,000 | $577 | $586 | $657 | $668 | 13.85% | 14.00% |
| | 6,000 | $812 | $821 | $927 | $938 | 14.13% | 14.23% |
| | 8,000 | $1,048 | $1,056 | $1,197 | $1,208 | 14.28% | 14.36% |
| | 10,000 | $1,283 | $1,291 | $1,467 | $1,478 | 14.37% | 14.44% |
| 30 | 9,000 | $1,236 | $1,245 | $1,420 | $1,431 | 14.89% | 14.95% |
| | 12,000 | $1,589 | $1,598 | $1,825 | $1,836 | 14.87% | 14.92% |
| | 15,000 | $1,942 | $1,950 | $2,230 | $2,241 | 14.86% | 14.90% |
| | 18,000 | $2,294 | $2,303 | $2,635 | $2,646 | 14.85% | 14.88% |

* Net rate including Schedules 91, 92, 290 and 291.

# Pacific Power
## Monthly Billing Comparison
## Delivery Service Schedule 28 + Cost-Based Supply Service
## Large General Service - Secondary Delivery Voltage

| kW Load Size | kWh | Monthly Billing* | | Percent Difference |
|---|---|---|---|---|
| | | Present Price | Proposed Price | |
| 15 | 3,000 | $400 | $424 | 5.99% |
| | 4,500 | $537 | $560 | 4.24% |
| | 7,500 | $810 | $830 | 2.52% |
| 31 | 6,200 | $808 | $851 | 5.33% |
| | 9,300 | $1,090 | $1,130 | 3.72% |
| | 15,500 | $1,654 | $1,690 | 2.16% |
| 40 | 8,000 | $1,037 | $1,091 | 5.18% |
| | 12,000 | $1,401 | $1,452 | 3.61% |
| | 20,000 | $2,129 | $2,174 | 2.08% |
| 60 | 12,000 | $1,547 | $1,625 | 5.01% |
| | 18,000 | $2,093 | $2,166 | 3.48% |
| | 30,000 | $3,186 | $3,249 | 1.99% |
| 80 | 16,000 | $2,051 | $2,151 | 4.84% |
| | 24,000 | $2,780 | $2,873 | 3.35% |
| | 40,000 | $4,236 | $4,317 | 1.90% |
| 100 | 20,000 | $2,556 | $2,677 | 4.74% |
| | 30,000 | $3,466 | $3,579 | 3.27% |
| | 50,000 | $5,287 | $5,384 | 1.84% |
| 200 | 40,000 | $5,053 | $5,280 | 4.47% |
| | 60,000 | $6,874 | $7,085 | 3.06% |
| | 100,000 | $10,516 | $10,694 | 1.70% |

* Net rate including Schedules 91, 92, 290 and 291.

# Pacific Power
## Monthly Billing Comparison
## Delivery Service Schedule 28 + Cost-Based Supply Service
## Large General Service - Primary Delivery Voltage

| kW Load Size | kWh | Monthly Billing* Present Price | Monthly Billing* Proposed Price | Percent Difference |
|---|---|---|---|---|
| 15 | 4,500 | $498 | $574 | 15.26% |
| | 6,000 | $627 | $700 | 11.66% |
| | 7,500 | $756 | $826 | 9.29% |
| 31 | 9,300 | $1,010 | $1,150 | 13.84% |
| | 12,400 | $1,276 | $1,410 | 10.48% |
| | 15,500 | $1,543 | $1,670 | 8.28% |
| 40 | 12,000 | $1,298 | $1,474 | 13.53% |
| | 16,000 | $1,642 | $1,810 | 10.23% |
| | 20,000 | $1,985 | $2,145 | 8.07% |
| 60 | 18,000 | $1,939 | $2,195 | 13.17% |
| | 24,000 | $2,455 | $2,698 | 9.93% |
| | 30,000 | $2,970 | $3,202 | 7.82% |
| 80 | 24,000 | $2,575 | $2,906 | 12.85% |
| | 32,000 | $3,262 | $3,578 | 9.67% |
| | 40,000 | $3,949 | $4,249 | 7.60% |
| 100 | 30,000 | $3,211 | $3,618 | 12.67% |
| | 40,000 | $4,070 | $4,457 | 9.52% |
| | 50,000 | $4,929 | $5,296 | 7.47% |
| 200 | 60,000 | $6,371 | $7,142 | 12.10% |
| | 80,000 | $8,088 | $8,820 | 9.05% |
| | 100,000 | $9,805 | $10,499 | 7.07% |

* Net rate including Schedules 91, 92, 290 and 291.

# Pacific Power
## Monthly Billing Comparison
## Delivery Service Schedule 30 + Cost-Based Supply Service
## Large General Service - Secondary Delivery Voltage

| kW Load Size | kWh | Monthly Billing* | | Percent Difference |
|---|---|---|---|---|
| | | Present Price | Proposed Price | |
| 100 | 20,000 | $3,004 | $3,387 | 12.74% |
| | 30,000 | $3,677 | $4,052 | 10.20% |
| | 50,000 | $5,022 | $5,382 | 7.16% |
| 200 | 40,000 | $5,565 | $6,073 | 9.12% |
| | 60,000 | $6,911 | $7,403 | 7.12% |
| | 100,000 | $9,601 | $10,063 | 4.81% |
| 300 | 60,000 | $8,284 | $9,008 | 8.74% |
| | 90,000 | $10,302 | $11,003 | 6.80% |
| | 150,000 | $14,338 | $14,993 | 4.57% |
| 400 | 80,000 | $10,889 | $11,769 | 8.08% |
| | 120,000 | $13,580 | $14,429 | 6.26% |
| | 200,000 | $18,961 | $19,750 | 4.16% |
| 500 | 100,000 | $13,526 | $14,577 | 7.77% |
| | 150,000 | $16,890 | $17,902 | 5.99% |
| | 250,000 | $23,617 | $24,553 | 3.96% |
| 600 | 120,000 | $16,164 | $17,385 | 7.55% |
| | 180,000 | $20,200 | $21,375 | 5.82% |
| | 300,000 | $28,272 | $29,356 | 3.83% |
| 800 | 160,000 | $21,439 | $23,001 | 7.29% |
| | 240,000 | $26,820 | $28,321 | 5.60% |
| | 400,000 | $37,583 | $38,962 | 3.67% |
| 1000 | 200,000 | $26,714 | $28,617 | 7.12% |
| | 300,000 | $33,440 | $35,267 | 5.46% |
| | 500,000 | $46,894 | $48,569 | 3.57% |

* Net rate including Schedules 91, 92, 290 and 291.

# Pacific Power
## Monthly Billing Comparison
## Delivery Service Schedule 30 + Cost-Based Supply Service
## Large General Service - Primary Delivery Voltage

| kW Load Size | kWh | Monthly Billing* Present Price | Monthly Billing* Proposed Price | Percent Difference |
|---|---|---|---|---|
| 100 | 30,000 | $3,630 | $3,907 | 7.64% |
| | 40,000 | $4,298 | $4,567 | 6.25% |
| | 50,000 | $4,967 | $5,226 | 5.23% |
| 200 | 60,000 | $6,845 | $7,177 | 4.85% |
| | 80,000 | $8,181 | $8,496 | 3.85% |
| | 100,000 | $9,518 | $9,815 | 3.12% |
| 300 | 90,000 | $10,202 | $10,665 | 4.54% |
| | 120,000 | $12,207 | $12,644 | 3.58% |
| | 150,000 | $14,212 | $14,623 | 2.89% |
| 400 | 120,000 | $13,486 | $14,029 | 4.03% |
| | 160,000 | $16,159 | $16,668 | 3.15% |
| | 200,000 | $18,832 | $19,306 | 2.52% |
| 500 | 150,000 | $16,771 | $17,406 | 3.78% |
| | 200,000 | $20,113 | $20,704 | 2.94% |
| | 250,000 | $23,455 | $24,002 | 2.33% |
| 600 | 180,000 | $20,057 | $20,782 | 3.61% |
| | 240,000 | $24,067 | $24,740 | 2.79% |
| | 300,000 | $28,077 | $28,697 | 2.21% |
| 800 | 240,000 | $26,629 | $27,535 | 3.40% |
| | 320,000 | $31,976 | $32,812 | 2.61% |
| | 400,000 | $37,322 | $38,089 | 2.05% |
| 1000 | 300,000 | $33,201 | $34,288 | 3.27% |
| | 400,000 | $39,884 | $40,884 | 2.51% |
| | 500,000 | $46,567 | $47,480 | 1.96% |

* Net rate including Schedules 91, 92, 290 and 291.

# Pacific Power
## Billing Comparison
## Delivery Service Schedule 41 + Cost-Based Supply Service
## Agricultural Pumping - Secondary Delivery Voltage

| kW Load Size | kWh | Present Price* Monthly Bill | Present Price* Annual Load Size Charge | Proposed Price* Monthly Bill | Proposed Price* Annual Load Size Charge | Percent Difference Monthly Bill | Percent Difference Annual Load Size Charge |
|---|---|---|---|---|---|---|---|
| Single Phase | | | | | | | |
| 10 | 2,000 | $233 | $174 | $260 | $241 | 11.65% | 38.60% |
| | 3,000 | $350 | $174 | $391 | $241 | 11.65% | 38.60% |
| | 5,000 | $583 | $174 | $651 | $241 | 11.66% | 38.60% |
| Three Phase | | | | | | | |
| 20 | 4,000 | $466 | $347 | $521 | $481 | 11.66% | 38.60% |
| | 6,000 | $700 | $347 | $781 | $481 | 11.65% | 38.60% |
| | 10,000 | $1,166 | $347 | $1,302 | $481 | 11.65% | 38.60% |
| 100 | 20,000 | $2,332 | $1,604 | $2,604 | $2,223 | 11.65% | 38.61% |
| | 30,000 | $3,499 | $1,604 | $3,906 | $2,223 | 11.65% | 38.61% |
| | 50,000 | $5,831 | $1,604 | $6,510 | $2,223 | 11.65% | 38.61% |
| 300 | 60,000 | $6,997 | $3,979 | $7,813 | $5,511 | 11.65% | 38.52% |
| | 90,000 | $10,496 | $3,979 | $11,719 | $5,511 | 11.65% | 38.52% |
| | 150,000 | $17,493 | $3,979 | $19,531 | $5,511 | 11.65% | 38.52% |

* Net rate including Schedules 91, 92, 98, 290 and 291.

# Pacific Power
# Billing Comparison
# Delivery Service Schedule 41 + Cost-Based Supply Service
# Agricultural Pumping - Primary Delivery Voltage

| | | Present Price* | | Proposed Price* | | Percent Difference | |
|---|---|---|---|---|---|---|---|
| kW Load Size | kWh | Monthly Bill | Annual Load Size Charge | Monthly Bill | Annual Load Size Charge | Monthly Bill | Annual Load Size Charge |
| Single Phase | | | | | | | |
| 10 | 3,000 | $344 | $172 | $384 | $238 | 11.63% | 38.46% |
| | 4,000 | $459 | $172 | $512 | $238 | 11.63% | 38.46% |
| | 5,000 | $573 | $172 | $640 | $238 | 11.63% | 38.46% |
| Three Phase | | | | | | | |
| 20 | 6,000 | $688 | $343 | $768 | $475 | 11.63% | 38.46% |
| | 8,000 | $917 | $343 | $1,024 | $475 | 11.63% | 38.46% |
| | 10,000 | $1,147 | $343 | $1,280 | $475 | 11.63% | 38.46% |
| 100 | 30,000 | $3,440 | $1,573 | $3,841 | $2,192 | 11.63% | 39.35% |
| | 40,000 | $4,587 | $1,573 | $5,121 | $2,192 | 11.63% | 39.35% |
| | 50,000 | $5,734 | $1,573 | $6,401 | $2,192 | 11.63% | 39.35% |
| 300 | 90,000 | $10,321 | $3,908 | $11,522 | $5,440 | 11.63% | 39.22% |
| | 120,000 | $13,762 | $3,908 | $15,362 | $5,440 | 11.63% | 39.22% |
| | 150,000 | $17,202 | $3,908 | $19,203 | $5,440 | 11.63% | 39.22% |

* Net rate including Schedules 91, 92, 98, 290 and 291.

# Pacific Power
## Monthly Billing Comparison
## Delivery Service Schedule 48 + Cost-Based Supply Service
## Large General Service - Secondary Delivery Voltage
## 1,000 kW and Over

| kW Load Size | kWh | Monthly Billing | | Percent Difference |
|---|---|---|---|---|
| | | Present Price | Proposed Price | |
| 1,000 | 300,000 | $32,764 | $35,450 | 8.20% |
| | 500,000 | $47,055 | $49,806 | 5.85% |
| | 700,000 | $61,346 | $64,162 | 4.59% |
| 2,000 | 600,000 | $64,939 | $70,077 | 7.91% |
| | 1,000,000 | $91,729 | $97,111 | 5.87% |
| | 1,400,000 | $119,203 | $124,718 | 4.63% |
| 6,000 | 1,800,000 | $180,421 | $197,041 | 9.21% |
| | 3,000,000 | $262,842 | $279,860 | 6.47% |
| | 4,200,000 | $345,263 | $362,679 | 5.04% |
| 12,000 | 3,600,000 | $358,683 | $391,268 | 9.08% |
| | 6,000,000 | $523,145 | $556,527 | 6.38% |
| | 8,400,000 | $687,075 | $721,253 | 4.97% |

Notes:

| | |
|---|---|
| On-Peak kWh | 38.20% |
| Off-Peak kWh | 61.80% |

* Net rate including Schedules 91, 92, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

# Pacific Power
## Monthly Billing Comparison
## Delivery Service Schedule 48 + Cost-Based Supply Service
## Large General Service - Primary Delivery Voltage
## 1,000 kW and Over

| kW Load Size | kWh | Monthly Billing | | Percent Difference |
|---|---|---|---|---|
| | | Present Price | Proposed Price | |
| 1,000 | 300,000 | $31,058 | $36,275 | 16.80% |
| | 500,000 | $45,050 | $50,328 | 11.72% |
| | 700,000 | $59,043 | $64,382 | 9.04% |
| 2,000 | 600,000 | $61,537 | $71,393 | 16.02% |
| | 1,000,000 | $87,643 | $97,837 | 11.63% |
| | 1,400,000 | $114,507 | $124,825 | 9.01% |
| 6,000 | 1,800,000 | $176,526 | $206,267 | 16.85% |
| | 3,000,000 | $257,117 | $287,232 | 11.71% |
| | 4,200,000 | $337,708 | $368,197 | 9.03% |
| 12,000 | 3,600,000 | $350,923 | $408,789 | 16.49% |
| | 6,000,000 | $511,725 | $570,338 | 11.45% |
| | 8,400,000 | $671,996 | $731,355 | 8.83% |

Notes:

| | |
|---|---|
| On-Peak kWh | 37.89% |
| Off-Peak kWh | 62.11% |

* Net rate including Schedules 91, 92, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

# Pacific Power
## Monthly Billing Comparison
## Delivery Service Schedule 48 + Cost-Based Supply Service
## Large General Service - Transmission Delivery Voltage
## 1,000 kW and Over

| kW Load Size | kWh | Monthly Billing | | Percent Difference |
|---|---|---|---|---|
| | | Present Price | Proposed Price | |
| 1,000 | 500,000 | $42,973 | $48,307 | 12.41% |
| | 700,000 | $56,452 | $61,840 | 9.55% |
| 2,000 | 1,000,000 | $83,253 | $93,084 | 11.81% |
| | 1,400,000 | $109,067 | $119,010 | 9.12% |
| 6,000 | 3,000,000 | $247,194 | $276,221 | 11.74% |
| | 4,200,000 | $324,634 | $353,996 | 9.04% |
| 12,000 | 6,000,000 | $491,621 | $546,936 | 11.25% |
| | 8,400,000 | $645,588 | $701,575 | 8.67% |

Notes:

| | |
|---|---|
| On-Peak kWh | 37.47% |
| Off-Peak kWh | 62.53% |

* Net rate including Schedules 91, 92, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

Docket No. UE 433
Exhibit PAC/3508
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Reply Testimony of Robert M. Meredith**

**Updated Cost of Eliminating Payment Fees**

**July 2024**

**PacifiCorp**
**State of Oregon**
**Cost of Eliminating Payment Fees**
**Average of 36 Months Ending December 2023**

| Description | Fee Count | Fee | Total Annual Cost |
|---|---|---|---|
| Pay Station | 77,533 | $1.65 | $127,930 |
| Residential Card Payment | 609,190 | $1.99 | $1,212,289 |
| Residential ACH Payment | 24,413 | $1.99 | $48,583 |
| Non-Residential Card Payment | 21,160 | $7.99 | $169,068 |
| Non-Residential ACH Payment | 1,594 | $7.99 | $12,736 |
| **Total** | 733,891 | | **$1,570,606** |